THE EIGHTH CERI INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

October 22-24, 1989
Calgary, Alberta

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TABLE OF CONTENTS

SECTION 1

Keynote Addresses

"The State of the World Oil Market"

Mr. George Quincey Lumsden
Director, Oil Market Developments
International Energy Agency
Paris, France

"The U.S. National Energy Strategy"

Mr. Thad Grundy, Jr.
Deputy Assistant Secretary-Designate
International Affairs
United States Department of Energy
Washington, D.C.

"OPEC Oil in the 1990s"

His Excellency Dr. Subroto
Secretary General
Organization of Petroleum Exporting Countries
Vienna, Austria

Panel Presentations

SECTION 2

"WORLD OIL MARKET PERSPECTIVES"

"World Energy Prospects: An Overview"

Dr. John Kyle
Corporate Economist
Exxon Corporation
New York

"Medium Term Supply and Demand Outlook"

Dr. Nestor Ramirez
Trade and Supply Coordinator
Petroleos de Venezuela S.A.
Caracas, Venezuela

SECTION 2 (Cont'd)

"Certain Considerations Affecting the World Oil Market"

Hon. Melvin Conant
President, Conant and Associates, Ltd.
Editor, Geopolitics of Energy
Washington, D.C.

SECTION 3

"INTERNATIONAL GAS MARKETS"

"The European Natural Gas Market"

Prof.dr. Peter Odell
Director, Centre for International Energy Studies
Erasmus University
Rotterdam, Netherlands

"Outlook for LNG Markets Worldwide"

Mr. Malcolm Peebles
Director
Shell International Gas Ltd.
London, England

"LNG Supply/Demand in Japan"

Dr. Tsutomu Toichi
Chief Economist
Institute of Energy Economics
Tokyo, Japan

SECTION 4

"DOWNSTREAM INVESTMENTS"

"The Prospects for Downstream Investment in the European Community"

Mr. Gordon Langridge
formerly Head of Oil Marketing Division
Directorate General for Energy
Commission of the European Communities
Brussels, Belgium

"Downstream Prospects for the U.S. Petroleum Industry"

Mr. Bernard Picchi
Managing Director
Salomon Brothers Inc.
New York

SECTION 4 (Cont'd)

"Future Investment in the Downstream in Canada"

Mr. Gareth Crandall
President
Hycarb Engineering Ltd.
Calgary, Alberta

SECTION 5

"NORTH AMERICAN GAS MARKETS"

"Natural Gas in North America--The Next Few Years"

Mr. James Gray
Executive Vice President
Canadian Hunter Exploration Ltd.
Calgary, Alberta

"Ontario Gas Market Developments"

Mr. John Hunter
Vice President, Gas Supply
Union Gas Limited
Chatham, Ontario

"Perspectives on a 'Hot' Market for Gas"

Mr. Jacek Makowski
President
J. Makowski Company, Inc.
Boston, Massachusetts

"California Natural Gas Demand"

Mr. Richard Bilas
Commissioner
California Energy Commission
Sacramento, California

"Regional Pipeline Constraints and Developments"

Mr. Frederick Duda
Commissioner
California Public Utilities Commission
San Francisco, California

"An Iroquois Update"

Mr. Robert Reid
President
Iroquois Gas Transmission System
Shelton, Connecticut

SECTION 6 "OIL AND GAS EXPLORATION AND DEVELOPMENT IN THE 1990s"

"Regions with High Growth Potential"

Mr. Peter Gaffney
Senior Partner
Gaffney, Cline & Associates
Hampshire, England

"Colombian Perspective in the Petroleum Industry"

Mr. Enrique Amorocho
Vice President, Refining & Transportation
Empresa Colombiana De Petroleos (ECOPETROL)
Bogota, Colombia

"Petroleum Exploration and Development Prospects in Australia"

Mr. Bob Alderson
Assistant Secretary, Petroleum Policy
Australian Department of Primary Industries & Energy
Canberra, Australia

"The Strategy of the U.S. Producer"

Mr. James McColgin
President and General Manager
Conoco Canada Limited
Calgary, Alberta

"Oil and Gas Exploration and Development in the 1990's, the Canadian Scene"

Dr. Paul Merki
Vice President, Exploration
Shell Canada Limited
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THE STATE OF
THE WORLD OIL MARKET

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Keynote Comments by
George Quincey Lumsden, Jr.
Director, Oil Market Developments
International Energy Agency
Paris

to the
Eighth CERI
International Oil & Gas Markets Conference

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Convention Center
Calgary, Alberta
Canada
23 October 1989

Good morning. I would like first to express my thanks to the Canadian Energy Research Institute, and particularly to Dr. Angevine and Ms. Nancy Sanford for honouring me with this invitation to say a few words to you about energy in general and oil in particular. Let me also note my appreciation for the favour of being placed as your first keynote speaker. This way, when my task is done, I can truly relax and enjoy the rest of the excellent programme you have before you -- that is, if I come through this opener relatively unscathed.

Additionally, I would like the record to show that this is **not** my first visit to Calgary. I spent two weeks here during the Summer of 1948 -- my, how you've changed. But since I left no discernable impression on anyone hereabouts those many Summers ago, I guess I can now defy Will Roger's famous dictum: "You never get a second chance to make a first impression". Keeping up with the big leaguers on your programme, nevertheless, will not be easy. I sense "une tâche redoutable" in that I come from outside the industry and may see some aspects of oil markets from slightly different perspectives than those directly employed in it.

This is so because the International Energy Agency has only three Member countries that are net oil exporters: Norway, the United Kingdom, and Canada. It has eighteen other members who are net oil importers. Thus, if you believe that this numerical imbalance may from time to time constrain me to express a rather "consumerist" position, you will be right. I would ask my producer friends, however, to catch the full measure of my comments before they start shooting at me. What follows will, I think, indicate our belief that, if you survived the eighties, the nineties might again show that the oil and gas business is not such a bad one in which to be.

My task this morning is to engage in some general politio-economic speculation about the "State of the World Oil Market". I will try my best to set the stage for two ensuing days of discussions, during which speakers often having much more actual commercial experience and technical know-how than I about the production, transport, refining, and marketing of petroleum products will analyse details of what I may have only hinted at.

Experience tells me that when asked to comment upon the "state" of oil markets, I am really expected to treat not just where the market "is", or where it has "come from", but most of all, "where it may be going". This last, of course, is more tricky than the first two, particularly because you inevitably run into problems relating short-term perceptions to long-term concepts. Logic all too often gets strained trying to bridge the gap. The short-term picture is dominated by the projection of existing conditions, in order to facilitate "tactical" decisions re, for example, government or company policy for coming months. The process is essentially one gauged to assist micro-management. Conversely, the long-term view includes broad macro-economic "assumptions" which aim at a "strategy" to deal with perhaps a decade. Again, for example: in the current short-term, oil prices will probably not deviate too much from present levels. This has implications for operating stock policy, refinery margins, trading positions, and the year-end inventory figures to be presented in company annual reports. Conversely, in the long run, prices appear quite likely to rise in real terms, and this has implications for exploration and development investments, debt assumption, corporate decisions regarding major resource allocations, and other adjustments such as the entire range of energy and environment concerns which will dominate the 1990s -- et cetera.

Let us look at the short-term first and then the long. En route, I will try to bridge the two in order to amuse you and stimulate your criticism.

Oil consumption growth is now continuing along a trend line of between 1.5 and 2 per cent annually in the OECD area, and between 3.5 and 4 per cent in the non-OECD world. This trend is supported by sometimes fluctuating and geographically uneven -- but nevertheless persevering -- economic growth worldwide. Additionally, an unpredictable but persistent series of "other factors" such as draught, hurricanes, possibly earthquakes, and industrial accidents has also helped tighten the market and keep the margin of demand moving upwards just ahead of supply rates, which also continue to rise however. This market dynamic could change in coming months, if economic growth pauses and the upward movement of oil demand thus slows somewhat. Under these conditions, what might we expect of those producing the marginal barrel of oil?

Their current behaviour is evident. Some simple arithmetic applied to the Fourth Quarter 1989 column of Table 1 attached to our end-September Oil Market Report produces an October through December "call on OPEC" of 22.4 million barrels per day. Simultaneously, Table 2, appended to the same document, reveals OPEC production during September of 22.3 million barrels per day. The Organisation's Members are thus selling to the market, and for the past few months seem to have gauged it just about right. This is probably why the recently-concluded OPEC meetings in Geneva had little impact, commercially or psychologically. They were discounted almost entirely by the market when the nominal quota increases they granted were seen as having no effect at all on existing patterns of supply and also adhered strictly to the traditional pro-rata allocation system rather than grasping the nettle of a politically-charged reapportionment of market shares.

What might be assumed about the rest of this year? Some knowledgeable observers see sales from stocks -- which are traditional during the fourth quarter -- combining with continued high crude oil output to drive production beyond that sensitive margin of demand about which the market has balanced itself in recent months. They see a price softening, soon. Other observers -- just as knowledgeable -- see the precedent of trend-line demand growth and "other factors" as likely to continue delaying any significant market weakness, particularly as winter fuel oil requirements make themselves felt.

Thus, without fear of contradiction, we can report that, between now and the end of this year, oil markets will either weaken, or they will not weaken. This equivocal conclusion is, however, not without some merit. It forces us to consider what the producers of the marginal barrel might do in each of two instances.

First, if prices soften significantly, the OPEC Ministerial meeting scheduled for late next month is likely to be pre-occupied more with the disciplining of quotas than it is with their re-apportionment. Of course, some kind of pro-rata increase might still be approved. Nevertheless, as with other year-end meetings of the Organisation which we have witnessed in the recent past, the goal would be to generate de facto output restraint. While the level of this restraint might bear only a loose relationship to actually-assigned quotas, it would aim at having just enough physical and psychological impact on the market to permit those of us who are consumers to nudge the margin of demand back up to the point of relative equilibrium we have been experiencing throughout most of this year.

In the second instance, prices do **not** weaken, because consumer demand -- although rising less sharply than a year ago at this time -- continues to absorb most all production reaching the market. It is in this case where OPEC behaviour could again become quite interesting, as various proposals for quota redistribution are debated. The next OPEC meeting could even be remarkable if a re-apportioned quota system were actually to be accepted. Admittedly, any such reallocation might be small, and at the outset only be geared to legitimise the activities of second-echelon overproducers like Kuwait and the UAE, and to acknowledge that some other members, like Algeria and Libya, are simply no longer able to increase their production. Such a precedent-setting move, however, could prepare the way for an even more profound series of reallocations when Iraq and Iran next year find themselves with significantly greater oil export capacity in place than they now have. Saudi Arabia would then be confronted with the need to defend its own 5 million barrel per day quota, which is fully 2 million greater than each of the former belligerents in the Gulf War.

The ominous lesson for oil consumers in all of this, however, is that in contemplating fundamental market share re-apportionment, OPEC is simultaneously contemplating the likelihood of a return to a seller's market for oil. Whether or not its Members' thinking along these lines -- and it is a fact that they **are** thinking along these lines -- proves ultimately to be valid, will probably not depend so much upon their own actions. It is rather the actions of consumers worldwide -- not just within the OECD -- which will determine the speed and the degree to which those three major producers of the marginal barrel of the 1990s are able actually to accommodate each others' market share aspirations. The less they are called upon to compete, the closer we will be to the re-establishment of a seller's market.

Thus, while consumers must certainly welcome this apparent willingness by OPEC producers to adjust and increase their output to meet the future requirements of the market, it is also important for them to appreciate that that market will not necessarily have the type of buyer/seller balance which has prevailed for the past half-decade.

I have now reached the critical point in this presentation at which I attempt to move from the short term to the long term. In so doing, I will offer what I see as a fundamental principle which will influence both current and future oil markets. It is an ironic one, but it has as clear an applicability in the long-run as it does in the short-term example I have just utilised. This revelation is: in spite of what oil producers may proclaim to be their price and supply objectives, their actual activities in the marketplace almost invariably work to weaken prices. Conversely, no matter what oil consumers may claim to consider appropriate price and supply patterns, the resultant vector of all **their** activities in the marketplace is to raise prices.

Can this kernel of wisdom, which is currently valid, also serve as a point of departure for our now making some long-term assumptions? I think so. What follows are some of those assumptions -- all admittedly debatable -- regarding the evolution of the energy supply/demand balance in the 1990s. Emphasis is on oil's role in that balance.

The demand for, and thus the price of, crude oil and petroleum products in world markets will rise consistently during the coming decade. This phenomenon will be sustained by steady economic growth rates in the industrialised world, but still higher ones -- overall -- in the developing world. OECD gurus, looking through to the end of the next decade project a 2.7 per cent annual average GNP growth rate for present OECD members, an equal figure for the Centrally Planned Economies, and 3.8 per cent for the developing world. This is the fundamental drive behind oil and general energy demand.

Further, oil will remain the principal component of World Primary Energy Requirements, but while the volume of its use will increase, its percentage share of total energy consumption will decline. Oil use will concentrate more and more upon transport fuels in the OECD, but in energy-intensive industrialisation as well as in developing areas. Oil use in electricity will decline relative to other energy sources. More specifically, and assuming gradually rising prices through the coming decade, we project oil's share of the total world energy market to drop from its current 40 per cent to about 35 per cent. Its volume usage, however, should rise from somewhat over 3 billion metric tons annually now, to about 4 billion around the turn of the century.

Simultaneously as crude oil prices in real terms begin to rise, excess production and/or export capacity outside of the Persian Gulf region seems destined to decline. The U.S. "lower 48", Russia, the North Sea, China, Mexico -- all these areas demonstrate a pattern of declining prospects during the 1990s. As this occurs, supply and price will depend more and more upon the extent to which Middle East production and ultimately capacity is increased. I believe that significant increases will take place, and this brings us to a second fundamental principle, which should influence both short- and long-term views of the oil scene. It is that "OPEC sells to the market" and will continue to do so. I have already noted that over the past few months, the Organisation's Members seem to be hitting the margin of demand just about right, and that prices have held firm as a result. Certainly, there must be some luck attached to this, but it is also most likely that, during the 1990s, oil will continue to be produced and traded in a still more commercially sophisticated "high-tech" manner than was the case in the 1970s and early 1980s. This means not only that electronic trading will assist the day-to-day operations of the market, but that the production and capacity expansions to which I referred to will go forward at a rate which also permits some real price increases to take place. Or, one could turn this comment around and produce the equally valid observation that capacity investment is more likely in a rising price environment. It is, in fact, the 1986 market crash which caused so much of that investment to evaporate.

We estimate current world excess production capacity for crude oil to be somewhere between 8 and 10 million barrels per day. Outside of Venezuela, almost all of this is in the Persian Gulf, where market share perceptions have sharpened as the region faces reconstruction following the Iran-Iraq war. You have already heard my comments on the prospects for OPEC quota re-allocation and potential shifts in the market fulcrum between buyer and seller which relate thereto. It is that very atmosphere which will stimulate investment ahead of the curve of growing demand in order to assure the maintenance of market share -- possibly a re-apportioned one. In sum, we think there will be plenty of crude oil available to meet the oil demand of the 1990s. But this likelihood, in itself, does not resolve the consumer's problems -- even though he is resigning himself to the fact that he is going to be paying somewhat more for energy because of his own appetite for it. What are his other problems?

Rapidly rising environmental concerns could quite soon constrain use of certain types of oil and other energy sources in the OECD. This may cause problems in energy delivery systems, particularly as overtaxed refineries experience problems in getting the right product, to the right place, at the right time. Subsequently during the 1990s, persistently higher energy intensities in the non-OECD world than among OECD countries may further complicate these environmental and supply factors. Bluntly stated, "dirtier" types of industrial activities may migrate increasingly to the developing world. Or, as a means of assuring technology transfer and other assistance from the developed countries, poorer ones will try to "clean up their acts" and thereby increase worldwide competition for the lighter, whiter, environmentally-friendly end of the oil barrel.

Just how this evolving demand problem will share itself between the planet's major communities of nations -- West, East, and South -- is of concern. For now, we must admit we simply do not know. We are certainly studing it. One initial, disquieting indication is that the exportable surpluses of **all energy forms** from the world's major developing regions outside the Middle East are declining as their own economies and energy consumption grows. Included here are: Africa, Latin America, East Asia, and the Centrally Planned Economies. For the decade as a whole, and given consistently rising prices, we project world oil demand increasing at an average rate approaching 2 per cent per annum over the decade. The rate of growth would be higher over the medium term and lower over the latter part of the period. Oil demand is expected to rise most in the developing countries. For them, we would expect around 3 per cent per annum, largely because of rapid population growth, urbanisation, greater transport needs, and accelerating industrialisation -- particularly of heavy, relatively energy-intensive industries. The Centrally Planned Economies would also register about 2 per cent per annum, and the OECD countries would trail with an approximate 1 per cent average yearly increase. As a result, the non-OECD countries' share of world oil consumption could rise from 45 per cent in 1988 to about 52 per cent in 2005. During the same period, OECD countries' share could fall from 55 per cent to 48 per cent. Similar consumption-share realignments will affect other primary energy sources as well.

The fact that the share of OECD countries in world energy and oil consumption will probably pass from somewhat **over** to somewhat **under** 50% during the 1990s is fundamental to understanding the evolution of energy markets in the coming years. It compounds the environmental and supply factors which I have already noted to be the likely companions of increased non-OECD energy intensities.

Oil production outside the Middle East may actually expand **gradually** over time, but with a regional shift away from the OECD towards non-Middle East Developing countries. These, as noted, are likely to experience absolute declines in the energy surpluses they have available for export. Thus, with increasing world oil demand and only "modest" increases in non-Middle East supplies -- more and more of which will be kept at home -- world dependence on supplies from the Gulf will increase, perhaps by 10 to 15 per cent or to 34 to 35 per cent of the world total by the end of the century.

Rising world oil demand will remain the key motivator of the global energy balance in the 1990s. It will certainly have effects upon other forms of primary energy, which will continue to "follow" oil. Natural gas use should nearly double worldwide during the coming decade, most pronouncedly in the developing countries, where its use could **triple**. Coal will continue average rates of growth in the OECD, but with power generation becoming the pre-dominant factor, as other uses stagnate or decline. Centrally Planned Economies' consumption should be flat, but developing countries' use of coal will probably double during the coming decade. This would actually be somewhat less than during the past decade. Lower oil prices would keep heavy fuel oil in competition longer with both coal and gas. OECD use of hydropower will not be able to develop as fast as the growth in electricity demand. Similar hydro restrictions prevail in the Centrally Planned Economies, but they do not prevail in developing countries, where considerable room for growth exists.

Finally, nuclear power. It no longer enjoys undisputed cost advantages over alternative sources of electricity production. The environmental debate will be critical in affecting its future in the OECD. Centrally Planned Economies will apparently press ahead and register about half of the net additions to world nuclear power facilities during the next decade. Nuclear power will play an insignificant role among the Developing Countries in the 1990s.

With that, I have just about "shot-my-bolt" and will thus conclude with a summary of principal "keynote" points:

-- Several elements of the current short-term oil market outlook may be valid indicators of what the long term has in store; this is not always the case;

-- First among these is that worldwide, not just OECD, consumption is likely to continue firming prices, in spite of output increases by producers -- the sum of whose actions tend to weaken prices;

-- Oil producers may, therefore, occasionally surpass margins of demand and soften prices, but fundamental consumption growth will soon re-establish the earlier, firming trend;

-- In this context, however, OPEC is practising increasingly sophisticated market policies;

-- Consumers can only welcome the apparent willingness by OPEC to adjust and increase its output to meet their future requirements, but the coming twelve months could test continued viability of the buyer's market which has prevailed for the past several years;

- Oil will remain the principal component of world primary energy requirements, but while the volume of its use will increase, its percentage share of total energy consumption will decline;

- Oil use will focus more and more upon transport fuels, but along with gas, in energy-intensive industrialisation as well in developing areas. Oil's use in electricity should decline;

- During the 1990s, developing countries will demonstrate persistently higher energy intensities than those among the OECD countries;

- While environmental concerns among OECD countries are already constraining use of certain types of energy, it is the economic growth and energy intensities of developing countries which may further complicate global environmental and energy supply problems, as their exportable energy surpluses dwindle -- except in the Gulf;

- The share of OECD countries in energy consumption versus the rest of the world will pass from somewhat **over** to somewhat **under** 50 per cent sometime during the 1990s. This change in the global balance is fundamental to understanding the evolution of energy in the coming years.

I hope these remarks have provided some food for subsequent discussion. Thank you very much for your kind attention.

THE U.S. NATIONAL ENERGY STRATEGY

PRESENTED BY

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U.S. DEPARTMENT OF ENERGY

Eighth CERI International Oil and Gas Markets Conference
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Good Afternoon. I am very pleased to have the opportunity to speak with you today. Although I've just recently joined the Department of Energy, I've been involved in energy, in some form or another, for the last decade. I came to Washington from Houston, where we follow the oil and gas market almost as closely as you follow it here in Calgary.

In Washington, interest in the oil and gas industry spreads beyond the Department of Energy to others in our Administration, starting with President Bush. This Administration fully supports a healthy and vibrant oil and natural gas industry, both at home and abroad. We also recognize that environmental considerations will become increasingly important factors in our energy discussions.

Energy policy in the United States in the 1990s will follow a middle course between the market-intrusive activism of the 1970s and the laissez-faire attitudes of the 1980s. We will be activists in support of free but fair trade, effective international cooperation, and policies which strike a reasonable balance between our energy requirements and global environmental concerns.

This is in line with the overall principles and direction of President Bush's Administration. The President is a man with extensive experience in the international arena and broad personal knowledge of the oil and gas industry. He understands energy issues and their importance to economic growth and geopolitical stability. He recognizes the inherent strength of democratic nations with market economies. He is committed to working cooperatively within the international community to resolve common problems and promote economic and social progress around the world.

At the Department of Energy we have a knowledgeable, committed leadership team in place. Our specific mission is to design and direct energy policies and programs in support of the President's broad objectives: sustained, non-inflationary economic growth; good stewardship of the environment; and long-term strategic security.

Now these are easy goals to enunciate--eminently sensible to any audience. The challenge comes in their implementation--in developing and executing specific action plans that will actually achieve the broad policy and goals the country seeks. There are inevitable conflicts in the decision process: What benefits one energy sector may limit another; what is technologically feasible may be politically unpalatable; what is accepted as fact in one quarter may be sharply disputed in another. Yet in a democracy, such conflicts must give way to public consensus before effective actions can be undertaken.

This is precisely why President Bush has directed the Department to develop a national energy strategy--a strategy that will finally establish a comprehensive, fully credible data base on which we can begin to form consensus and implement a series of consistent, complimentary energy programs and policies for the United States.

Those who question the need for "yet another decision-delaying study" misunderstand the purpose and the focus of the National Energy Strategy. We have already begun to compile an energy data base to facilitate the decision process. As you well know, energy decisions are not made in isolation. Every choice has economic, environmental, strategic, and international components. Unless all of these are fully factored, the decision process is incomplete and open to argument.

Our purpose in the National Energy Strategy is to define our long-term energy goals and examine every energy option and alternative in its full context. The strategy will lay out our requirements, how they can be satisfied, and at what total cost. We will then make specific recommendations about how we believe the country should proceed in order to achieve our goals.

These recommendations will be a balanced package of proposals that seek to reconcile and integrate our energy, economic, environmental, and strategic interests on a consistent and long-term basis. Critics may be able to challenge our conclusions, but not our facts.

For example, right now public concern and anger over the recent oil spill in Alaska is being exploited to justify further bans on offshore drilling in Alaska and other coastal areas. This is neither sound energy policy nor sound environmental policy since less offshore production will actually increase U.S. oil imports and tanker traffic, and therefore create a greater risk of more spills and the very environmental damage people seek to prevent.

This is a clear case of a totally misplaced response to a serious environmental problem. Yet in the present highly-charged atmosphere, it is virtually impossible to make people understand that prohibiting offshore activity could actually aggravate environmental problems, as well as cost American jobs and add to our trade deficit.

We expect the strategy to address such complex issues--first, to present the facts and then to lay out the full range of options, alternatives, and consequences for every energy decision. Then our citizens will be able to make informed choices about the most desirable energy course to follow.

In developing our National Energy Strategy, we are soliciting views from all interested parties--from large corporations and small businesses, from environmental groups, scientists, elected officials, consumers, and every other group with information to contribute.

We also want to bring our international trading partners into the strategy development process. The United States is and will continue to be a major producer and consumer of all forms of energy. We understand that decisions we make in our National Energy Strategy may have effects far beyond our borders, and we welcome the input and cooperation of industry leaders and government officials from every country.

The National Energy Strategy is a critical part of our overall commitment in the Department to give clear focus and firm direction to our energy policy for the long-term. We are concentrating our efforts in three broad areas:

- Basic scientific and technical research to develop the credible data we need to assess risks, costs, and benefits and make informed energy decisions;

- Near-term R&D to establish economically efficient, environmentally sound technologies for the production and utilization of every energy resource;
- Better cooperation to promote the free flow of energy products and services in the global marketplace, and to encourage the rapid dissemination of effective technology around the world.

Whether in the area of coal exports and clean coal technologies--in worldwide nuclear safety practices and environmental restoration--or in joint research into issues affecting global climate change, the United States is committed to working with other nations to further our mutual interests. But we also believe that this must be a two-way street--that our businessmen must be as welcome in other countries as our scientists, our goods and services, and our expertise.

THE EXPORT INITIATIVE

That is why the Department has launched a major export initiative, closely coordinated with the Departments of State and Commerce and the U.S. trade representative. The export initiative will help American companies identify opportunities and overcome barriers to effective competition in international projects. We are concentrating initially on the petroleum services and equipment sector, but see the initiative expanding to include all energy sectors.

Right now, we are examining oil and gas activity worldwide, evaluating the ability of our domestic companies to respond, and determining what roadblocks may exist. We are also interested in getting American businessmen together with government officials in the producing countries, to see where there might be a beneficial fit. We are considering a whole range of options, from sponsoring symposia and trade missions in key areas, to closer Departmental monitoring of worldwide energy-related trade activity and more substantive ministerial level meetings.

International markets represent the best opportunity for American companies to remain profitable during difficult times at home. More and more companies are reaching the point where well over 50 percent of their revenues come from overseas business. The export initiative is designed to aid the energy industry in taking advantage of the tremendous opportunities that exist in the international arena. Enhancing energy security while strengthening one of our most important industries is a top priority at the Department of Energy.

U.S./CANADA - THE FREE TRADE AGREEMENT

The U.S./Canadian Free Trade Agreement (FTA) is a prime example of government cooperation in the strengthening of a trade partnership. We want a long-term world-wide energy strategy which builds on the agreement we have forged with the Canadians. Energy is key to economic competitiveness, quality of life, and national security. we feel confident that the free trade agreement with Canada will continue to encourage the most efficient development of resources on both sides of the border for our mutual benefit.

The United States and Canada can both take a great deal of pride in the Free Trade Agreement and especially the energy section, because it establishes a market-based environment for energy trade with minimal government interference. It will certainly have positive long-range economic impacts, and is an important component in our energy future. It embodies a number of principles this Administration would like to see in our National Energy Strategy.

Because the Free Trade Agreement guarantees open and unrestricted energy trade for both countries, producers will have greater certainty about investment decisions and can develop energy resources without worrying about government interference. Consumers will benefit because they will have a greater choice among dependable, economic energy sources. Our energy intensive industries should become more competitive in international markets. And, finally, our mutual energy security will be enhanced because of increased opportunities to develop our own resources, as opposed to increasing our dependence on less secure, foreign supplies.

NATURAL GAS

The Free Trade Agreement has been particularly beneficial for natural gas trade. Both in terms of energy security and the environment, natural gas is a truly bright spot in the U.S. energy picture. Wellhead price decontrol was the Administration's first major energy victory. Now that constraints are finally being removed from both the supply and demand sides of the business, we expect an expanding market, healthy domestic production, and increased gas trade with Canada. Canadian imports currently provide 7 percent of all gas consumed in the U.S. market and reached a level of approximately 1.3 trillion cubic feet in 1988. Import levels are expected to increase again in 1989 and are expected to double by 1995. Our two countries currently do about $10 billion annually in energy trade, and we expect this will grow under the Free Trade Agreement.

THE CLEAN AIR BILL

Another topic of particular interest to us, which has global implications, is President Bush's clean air plan. On June 12, 1989, President Bush proposed a comprehensive program to improve our air quality by amending the Clean Air Act of 1970. The President's plan calls for the first major revisions to the Clean Air Act since 1977 and is designed to curb three major threats to the nation's environment and to the health of millions of Americans: acid rain, toxic air emissions, and urban air pollution.

To fight acid rain, which causes widespread damage to forests, lakes, and buildings, as well as posing a threat to human health, utilities and factories would have to cut sulfur dioxide emissions in half by the year 2000, from 20 million tons to 10 million tons emitted annually. Nitrate oxide emissions would be reduced by 2 million tons. In addition, the President's plan includes incentives to encourage utilities to use new anti-pollution devices so they can burn high-sulfur coal, which we have in abundance, without emitting large amounts of sulfur into the air.

The President's clean air plan will establish a set schedule for regulating major sources of toxic air pollution and require emitters to toxic air pollution to use the maximum available control technology (MACT) to sharply cut pollution. It is estimated that the first phase of the President's air toxics initiative will eliminate about three-quarters of the cancer deaths caused by toxic air emissions from factories and plants.

Finally, to improve urban air quality, the president's plan would cut emissions that cause urban ozone--the primary contributor to urban air pollution--nearly in half, and help bring all cities into compliance with air quality standards. The plan contains new initiatives to promote alternative fuels to reduce pollution from cars, buses, trucks and motor fuels by providing for the use of alternative fuels--such as clean burning methanol, natural gas, and ethanol--in the most seriously endangered cities. The President's plan is designed to ensure that one million clean-fueled vehicles per year are introduced into America's most polluted cities by the year 1997.

Energy and the environment affect not only neighbors, such as the U.S. and Canada, but the entire global community. Energy is truly the essential world commodity; it must be developed and traded freely. The producing countries need stable markets and the new capital they generate to further economic development. The consumer nations need secure supplies of reasonably-priced energy to maintain their economies and invest in vital, new technologies.

Energy is the commodity that most directly supports the world economy and social progress. Clean air, fresh water, and fertile lands are the necessities that sustain our lives. We cannot choose between these. We must find ways to ensure that energy, economic, and environmental policies are mutually reinforcing.

To a much greater extent than before, consensus exists that all nations benefit when energy supplies are adequate, freely traded at stable prices, and produced and used in ways that do not pollute our planet. The 1990's hold real opportunities, if we are willing to seize them and risk success.

Few would have predicted this consensus ten years ago. For all the turmoil of the 1980s, we have emerged with perhaps some important lessons learned and a far stronger energy foundation on which to build for the future.

Not we must set out an international agenda for the 1990s:

- The agenda must recognize the need for balanced, environmentally sound development and use of all the world's energy resources--oil, natural gas, coal, nuclear power, and renewable energy.

- The agenda must support fair trade of all goods and services, including energy products, services, and technologies.

- The agenda must give environmental considerations equal priority with economic factors in determining fuel supply decisions. Moreover, the costs of environmental compliance must be equitably distributed, so no nation is competitively compromised.

- The agenda must address nuclear safety and management issues on a worldwide basis, because radioactive fallout from a single plant anywhere quickly affects all of us. Nuclear operations in every country must be characterized by a policy of openness, individual responsibility up and down the line, and commitment to excellence.

- The agenda must expand international cooperation in the basic sciences and in technology R&D. Issues ranging from global climate change, to advanced resource recovery technologies, to grater end use efficiency, including extensive conservation efforts, all require our attention in the coming decade.

Yes, the opportunities are there, if we are willing to take advantage of them. Our challenge is to work together more effectively as a community of nations--no longer divided by fear and an uncertain future--but rather, bound now by a common commitment to international cooperation and the efficient, environmentally sound use of all the world's energy resources.

Let us begin now; let us pursue the agenda. Then, those who meet here in another ten years, at the millennium, may say of us:

They seized the opportunities;

They risked success;

They made a difference.

"OPEC OIL IN THE 1990s"

Final Edition of the Presentation by

H.E. Dr. Subroto
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Organization of Petroleum Exporting Countries (OPEC)
Vienna, Austria

EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

With just ten weeks remaining before the start of the new decade, I am especially grateful for the timely opportunity CERI has given me to comment on the prospects for the international oil industry in the 1990s. We are all familiar with the turbulent nature of the market during most of the 1980s, and some of you may be as eager as me to free ourselves of this troublesome decade as quickly as possible! The fact that this can be done on a note of cautious optimism about the market's future will be heartening to us all.

As we prepare to leave the 1980s, there is in fact a welcome air of tranquility in the market. In contrast with similar calm periods in the past, there is no accompanying mood of the lull before the storm.

Perhaps this congenial state of affairs has arisen from the increasing confidence around the world that through proper communication and dialogue, we can attenuate major international economic problems. This may, in turn, have permeated down from the general easing of tensions on the international political arena, most notably concerning the relationship between the two major "super powers". The sense of realism which has been a driving force in this detente has also manifested itself in the international oil market. In both cases, it is based upon the emerging consensus view that, if we all continue bashing our heads against the brick wall long enough, then eventually we shall fracture our skulls. It is far simpler to remove the wall!

OPEC will be pleased to celebrate its 30th anniversary next September in this healthy new climate. Throughout our history, there has been continual dissatisfaction with the fundamentals of the international oil market. In the 1960s, the domination of the multinational oil companies resulted in unjustifiably low price levels; while these prices were of paramount importance to the burgeoning economies of the post-war industrialized nations, they were nevertheless anathema to the social and economic development of the overwhelming majority of poorer countries who supplied the crude.

The inevitable consequence occurred during the 1970s when the frustrated oil-producing countries took every opportunity to gain control of their indigenous resources. One outcome of this, in combination with other exogeneous factors in a highly charged atmosphere of over-reaction and panic, was a large increase in the price of crude. This had a backlash of its own in the 1980s, when the efforts of industrialized nations to reduce reliance on OPEC oil by adopting conservation measures and seeking alternative sources of energy supply, including the extraction of crude from expensive, hazardous non-OPEC areas, brought about a glut in the market and the collapse of its price structure.

Happily, there are now signs that this unyielding atmosphere of mistrust and unease among producers and consumers is being regarded increasingly for what it is -- a hideous waste of the world's finite natural resources.

This new realism is typified by the recent actions of many front-line non-OPEC oi producers. They have met together in their twos and threes or in gatherings of as many as 13 representatives from non-OPEC oil-producing countries. Sometimes OPEC officials have been present at their meetings; on other occasions, they have attended OPEC meetings. Where it has not been expedient or possible to meet as a full participant, they have adopted observer status. Throughout, there has been the clear realization that we share a common concern for maintaining market stability.

I believe the most significant factor to emerge from the meetings of non-OPEC producers has been the publicly stated pledge of many of them to reduce their oil output in the interests of market stability. The very mention of this pledge, let alone its actual implementation, has in itself had a positive impact on stability in the hyper-sensitive oil market. We in OPEC have been exhorting fellow oil producers for years to cooperate with us in our endeavours to bring stability to the market. We realized in the early 1980s that, without such cooperation, stability would remain a pipedream.

It is with all this in mind that we are gratified to note the positive role played by officials from the Province of Alberta during the past years, in the interests of oil market stability. Their attendance at important OPEC/non-OPEC meetings has demonstrated that the quest for oil market stability is not just the mission of oil revenue-dependent Third World nations, but also has a much more acute cutting edge to it. For oil market stability is also central to the energy expansion programme in Alberta, in just the same way as it is in many other advanced industrialized societies.

The enhanced involvement of countries from the politically styled East, most notably the Soviet Union and some of its traditional Eastern European trading partners, presages a radical transformation of the world's energy supply and demand structure during the 1990s. If the present relaxing of East-West trade barriers continues, then the Soviet Union's position as the world's leading oil producer, together with its abundance of natural gas, will have a profound impact on world energy supply patterns. The spirit of "glasnost" will affect demand in a similar manner. This new order may mean that we will soon have to incorporate the Soviet Union and its traditional trading partners more directly into our global analyses.

When attempting to assess the growth potential of the international oil market during the coming decade, one must start several steps along the global macroeconomic path. The most obvious starting point, and probably the most alarming, is the projected rise in the world's population. This passed the one billion mark early in the 18th Century, doubled by around 1930, and reached five billion in mid 1987. According to World Bank projections, it is expected to exceed six billion in the year 2000, with almost the entire increase concentrated in the developing countries. If the standard of living of the people is to be raised, then the economic repercussions will be enormous and will clearly have a significant impact on energy demand.

The next step is to predict the average growth rate for the world's market economies. We believe that if the present inflationary trends in the industrialized countries, which constitute such a major social and political threat to them, are kept under control, the economic growth rate could lie between 2.5 per cent and 3.0 per cent over the next five years, and possibly remain at around 2.5 per until the turn of the century. This is based on the likely continuation of the average growth rate of slightly above 2.5 per cent so far in the 1980s, and 3.3 per cent in the recovery years since 1982. With a projected annual average growth rate of 5 per cent per year, the newly industrializing countries are expected to out-perform the OECD countries whose rate will be much closer to the world average.

Let us now look specifically at energy, and assume a scenario in which, as of 1990, the crude oil price remains constant in real terms at $18 per barrel. We must, at this point, acknowledge the structural changes in the advanced economies, which have led to the appearance of less energy-intensive industries, thus reducing energy demand per unit of future economic growth. Bearing all this in mind, we project world demand will increase from the existing 100 million barrels of oil equivalent per day to about 120-130 million barrels of oil equivalent per day by the turn of the century -- indicating an annual average growth rate of about 1.7 per cent. Regionally, energy demand growth in the OECD will decline gradually from the present two per cent per annum to about one per cent by the year 2000, while, in the developing countries, due to their lower per capita energy base, it will remain above two per cent. It will average about 1.5 per cent in OPEC Member Countries during the 1990s.

Oil's share of the total energy mix is projected to fall by 2 per cent to about 46 per cent by the year 2000, and that of gas to increase by 4 per cent to 22 per cent. While we expect coal's share to decline slightly from today's level of 22 per cent, the combined share of nuclear and hydro will stay at about 11 percent, or even drop slightly.

In absolute terms, world oil demand is projected to continue growing from 51 million barrels per day in 1989 to around 58 million barrels per day by the year 2000, with the OECD countries accounting for about three million barrels per day of the increase, and the developing countries the remaining four million barrels per day.

OPEC's share of the world oil trade, which has fallen heavily during the present decade to as low as 40 per cent in 1985, is expected to rise from the 1988 level of 46 per cent to about 54 per cent by the end of the century, bringing our Member Countries' total supply to 30 million barrels per day from 21-22 million per day today. Conversely, non-OPEC supplies are projected to fall by two million barrels per day in the same period.

On the face of it, the outlook for the international oil market during the 1990s is a healthy one, with an appreciable expansion in its size anticipated, even if oil's share of the overall energy mix declines marginally. At first glance, it would appear that the most likely beneficiaries of this will be those oil producers, principally Members of OPEC, which have the capacity to take up the slack in the market as it arises. But, when one examines the issue a little more closely, one can see that consumers will also gain from the fact that there will still be plenty of oil around well into the 21st century to enable them to fuel their existing industrial enterprises without radical restructuring. Nevertheless, this potentially favourable situation can get out of hand so easily if no firm multilateral measures are adopted to contain the purely laissez-faire approach to oil market management.

This dichotomy has generated the core of OPEC's message -- that stability is vital for the future health of the international oil market, and ipso facto the world energy industry at large. But stability will not come of its own accord. It must be strived for by people with the future welfare of the international oil market at heart. OPEC as an Organization once again urges its many colleagues in the industry to cooperate with us in attempting to bring about this stability. The 1980s have been characterized by an abundance of losers in the international oil market, whether through direct involvement in its operations or through such peripheral phenomena as massive debt problems and bankruptcies attributable to the perpetual market weakness and uncertainty, most notably in 1986. There is no need for the repetition of this in the 1990's.

At OPEC, we are taking measures to put our own house in order. The quota issue has remained a stumbling block to our Organization's cohesiveness, and this has undermined our ability to stabilize the oil market. Despite the complex nature of this problem, our Organization has from time to time come up with temporary solutions which have engendered a certain degree of market stability. Last month's Meeting of our Ministerial Monitoring Committee in Geneva once more took a hard look at this problem. Judging from the open-mindedness that characterized the Meeting, and the genuine desire by all those present to resolve this issue, I am more convinced than ever that a permanent solution is in sight. Such a solution would go a long way towards adding new life to the Organization and putting us in a better position to face up to the new challenges of the 1990s.

Ladies and gentlemen, regardless of how the industry may develop during the coming years, I should like to reassure you that OPEC's principal resolve will continue unchanged in the 1990s -- namely, the achievement of a stable, orderly international oil market, with equitable returns for its multifarious participants. The indications are that oil will remain the world's most strategic, versatile and comparatively speaking, cheap and abundant energy resource well into the next century. Its role will remain central to the welfare of industrialized society, and we shall retain our firm conviction that a means must be found of utilizing this steadily depleting, finite resource in the optimal manner. But this will involve all of the interested parties cooperating with each other. Consumers must be prepared to offer producers fair, predictable levels of demand, unimpaired by restrictive trade practices. In return, producers will seek to guarantee security of supply.

When we look forward to the 1990s, we do so with a yearning that we can tread confidently into a future characterized by a positive or cooperative stance from all parties. After all, politically, economically and technologically we are living in a period of increasing globalization, where inter-dependency is vital to the manageability of all of our societies. Progress in any field depends upon the willingness and ability of nations to cooperate with each other to achieve mutually beneficial solutions. The recent improvement in the climate for international cooperation may enhance our ability to fight poverty and the environmental problems facing the world's population.

The global issue of environmental protection can no longer be ignored. It is a problem which affects us all; it is no respecter of national borders. We in OPEC, as well as our brothers and sisters in other developing countries, are as concerned about the state of the environment as anyone in the industrialized nations. We are equally aware of the fact that mankind's negligence is already making a profound, destructive impact on our planet's life-forms.

Nevertheless, we must seek to expand our knowlege of the true causes of many of the environmental phenomena, which by no means are all energy-related. The scale of the problem is immense, with both local and global connotations, and we cannot therefore expect cheap solutions. Furthermore, while we should take immediate action where possible, we must also recognize that we are talking about a long-term problem.

Policies based on emotions or short-term financial advantage rather than sound scientific grounds or longer-term economic realities will only result in unnecessarily expensive and wasteful energy exploitation, with the concomitant uncertainty on the world's commercial and industrial landscape. We should endeavour to adopt policies which will bring about global economic growth within the context of a clean and invigorating environment. Such policies must necessarily entail the provision of secure energy supplies at fair and moderate prices. We in OPEC are willing to contribute towards the achievement of such a noble objective in the 1990s.

As energy plays a critical role in development patterns and environmental quality, there are enormous opportunities for the petroleum industry to provide leadership in promoting forms of development that are environmentally sound and can be sustained to provide benefits to present and future generations.

The oil industry -- with its high technical, managerial and financial resources, its vast experience in operating in all regions of the world, and intensive contacts with its retail, commercial and industrial consumers that depend upon it for energy and petroleum products -- has significant direct and indirect influence on how energy will be used and hence the impact on the environment.

The oil industry for over a century has had a proven track record in responding effectively to change. This industry can contribute enormously to the new decade and make this into not just a new growth era, but an environmentally sound and sustained growth era.

I think a crucial strategy for the oil industry -- OPEC, non-OPEC and consuming countries -- is what I might call "consensus building", working towards the development of a world energy strategy which is sensible and consistent. For the 1990s the watchword should be "Energy Interdependence". Wise use of the world's resources will require communication, dialogue and cooperation. Among all the players in the industry, the challenges that are emerging are unprecedented.

WORLD ENERGY PROSPECTS: AN OVERVIEW

Presented by

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EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta

October 22-24, 1989

DRAFT
October 17, 1989

Good Morning

I would like to begin by expressing my thanks to Gerry Angevine for inviting me to participate in this conference. From my present location in New York, opportunities to visit Western Canada are infrequent. With so many former colleagues here, I really appreciate the chance to renew old friendships, and to be able to make a few new ones over the next two days.

As I understand the objective of this panel, it is to provide some perspectives on the world oil market that will serve both to stimulate a discussion with you, the audience, this morning, and also set the stage for the remainder of the conference. Accordingly, I will provide a brief summary of our long-term world energy outlook to 2010. I will also comment briefly on principal near-term uncertainties in the world oil market.

SLIDE #1: ECONOMIC UNDERPINNINGS

- I'll start with economic projections, because the world economy is the most important driver of energy markets. Our projections have two different time dimensions. For the longer term we estimate "steady state" growth rates. At the top of this chart I've characterized in very summary form some key free world (world less CPEs) variables out to 2010 from today: population growth averages 1.6%/year, the economy grows 2.6%/year and, by contrast, energy use increases at 1.4%/year. I'll elaborate in a moment on the relationship between energy and economic growth. But the basic point is that this is an exercise in compound interest, the cumulative effect of which accounts for substantial absolute growth in energy markets.

- In addition, over the nearer term -- out to about 1995 -- we also take account of identifiable factors that may alter the basic trends. For example, in the U.S. we expect much slower growth in 1990, but no outright decline in GNP. While the U.S. is, we think, slowing down, Europe seems to be doing very well, in large part as a result of positive expectations for increased economic integration. Japan also continues to boom. Among the LDCs the Far East growth stands out. While the unraveling of the Latin American debt crisis is making progress, it is slow, and will retard growth in that region.

SLIDE #2: ENERGY EFFICIENCY TRENDS

- The next chart elaborates on the relationship between economic growth and energy use. One simple measure of energy efficiency is the relationship between economic growth and energy use. This chart shows that from 1960 to 1973, a period of very low oil and energy prices, energy use grew faster than GNP and the world became less energy efficient. But with sharply higher prices in the early and late '70s, this changed. From '73 to '85 energy use grew much more slowly than GNP -- efficiency gained significantly. In the late '80s efficiency gains slumped as economic growth accelerated and energy prices fell. In contrast, our projections to 2010 again assume significant gains in energy efficiency. The rationale is that over this long period we expect oil and energy prices to rise and also there are likely to be various pressures to achieve energy efficiency for environmental reasons.

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SLIDE #2: ENERGY EFFICIENCY TRENDS (continued)

o Everyone, it seems, is rediscovering the importance of the environment. Let me note here that, although I will not identify specific environmentally-driven impacts on our projections, we do assume both price-driven and regulation-driven changes in energy usage in response to environmental pressures. However, we have not assumed any major mandated life style changes, nor have we assumed the invention of any silver bullets to solve environmental problems. The outlook is thus evolutionary rather than revolutionary. Obviously, it is also uncertain.

o With that as background ...

SLIDE #3: ENERGY DEMAND BY REGION

- Energy growth in the non-CPE world is expected to average about 1.4% per year between now and 2010.

- In the industrialized areas, energy demand is forecast to grow only about 0.8% per year, due to increased efficiencies and conservation plus a continuing shift to less energy intensive activity. Within the industrialized countries, energy growth forecasts roughly parallel the outlooks for economic growth, with faster growing countries experiencing faster increases in energy use.

- Energy demand in the LDCs is expected to grow at over three times the rate in the industrialized countries. This growth is driven by rising per capita consumption as living standards improve, migration of energy-intensive industries from developed countries, and continued industrialization of these economies.

- The LDCs will play an increasingly important role in future energy markets with about 70% of the gas, 40% of the coal and virtually all the growth in oil demand occurring in these countries.

SLIDE #4: ENERGY DEMAND BY FUEL

- Looking at energy demand by fuel type, natural gas [2.2% per year growth] is the fuel of choice in more markets as availability of supply enables its introduction into new markets. Environmental considerations in the future will put greater emphasis on burning gas rather than "dirtier" fuels.

- Coal [1.9% per year growth] grows slightly in share as it remains the cheapest source of bulk energy and the preferred fuel for power generation in countries with large indigenous coal reserves. Although requirements to meet current environmental problems such as acid rain have been factored into our outlook, this level of coal growth is potentially vulnerable to any future steps aimed at lowering the greenhouse warming impact of carbon dioxide emissions.

- Nuclear growth is being affected by environmental considerations in the U.S. and most European countries. Almost no growth occurs in these countries after currently planned plants start up in the early 90s. However, in the rest of the Free World, especially in Japan and Canada, nuclear's share of the power generation market continues to grow.

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SLIDE #4: ENERGY DEMAND BY FUEL (continued)

- The growth in liquids use over the outlook period is less than other fuels [0.6% per year] with substitution and conservation steps accelerating as oil prices rise. The increase in liquids use is almost exclusively for transportation fuels and chemicals feedstocks.

SLIDE #5: LIQUIDS DEMAND BY REGION

- In our view, liquids use in the industrial nations is very responsive to price. Recently, with oil prices at low levels, consumption has grown markedly, averaging about 2% per year. With relatively low oil prices in the early/mid 1990s, liquids consumption is projected to grow annually at rates of about 1.5% per year. This period is characterized by increasing oil demand due to slower energy efficiency gains and less oil substitution by other fuels.

- Post-2000, liquids consumption is forecast to remain almost flat as higher prices stimulate additional conservation and more efficient oil use.

- Liquids use is forecast to remain steady in the industrialized countries through the year 2000. After the turn of the century, liquids use in these countries is expected to decline at a rate of 0.6% per year. A key factor in this decline is improving transportation efficiency.

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SLIDE #5: LIQUIDS DEMAND BY REGION (continued)

- The LDCs are the only area of steady liquids demand growth, increasing at a rate of 2% per year over the outlook period. By 2010, 41% of liquids demand is in the LDCs compared to 30% today. This LDC liquids demand growth, which is primarily in the transportation sector, is consistent with their higher projected economic growth rates, more energy intensive phase of industrialization, and improved standard of living.

SLIDE #6: WORLD LIQUIDS PRODUCTION

- Turning next to the world liquids supply picture, note first that this is the entire world, and includes supplies from the CPEs.

- In recent years, production outside of OPEC has increased significantly. Prudhoe Bay, Mexico and the North Sea accounted for over 75% of this increase. Industry has not made discoveries of comparable size in recent years and the resource inventory is increasingly being drawn down.

- In the U.S., production is expected to decline until about 2000. The underlying reasons are: first, in the lower 48 (L48) and Gulf of Mexico (GOM), prices are not expected to be high enough to provide incentives for the drilling activity required to maintain production, and second, the Alaska fields now appeared to have entered their declining stage. Post 2000, in response to higher prices, reserve adds roughly balance the continued decline of the fields. Net import dependence is expected to grow from under 40% of consumption currently to above 50% by 2000.

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SLIDE #6: WORLD LIQUIDS PRODUCTION (continued)

- A few non-OPEC countries such as Mexico and Brazil, are expected to increase production over the outlook period. As a group, however, our base case outlook shows production from other non-OPEC countries essentially flat. Whether production outside of OPEC resumes its upward trend again in the 1990s is certainly an issue worthy of consideration. Our base case does not make this assumption, but we recognize that there are conditions under which this might occur.

SLIDE #7: POTENTIAL DEMAND FOR OPEC CRUDE

VG OFF

- Against that background, virtually all of the growth in liquids is expected to be met by OPEC.

- In this chart, the top line repeats the total liquids demand I showed earlier. The top wedge is our estimate of the portion which will be supplied by OPEC crude oil.

- OPEC's share of this market peaked at over 60% in the early 1970s. After the second oil shock, falling demand and rising non-OPEC production caused OPEC production to halve and OPEC's share to fall to 38%. But with demand growing again, and the other supplies stable and projected to decline, OPEC volumes are projected to increase slowly but steadily. Note that OPEC does not exceed its peak production levels of the 70s, nor does their share of the market return to its previous highs. However, the steady increase in production does suggest that time will tend to strengthen OPEC's market position once again.

SLIDE #8: NEAR-TERM OPEC CRUDE REQUIREMENTS

VG-OFF

o If we focus on the near-term crude oil market, there are a number of uncertainties.

VG-ON

o This next chart shows free world crude oil supply-demand balances for 1987 and 1988, together with an unexceptional forecast for 1989 and 90. Several interesting points can be drawn from the chart.

o First, over the entire period 1987-1990, we expect demand to have grown by some 3.6 million barrels per day. Of that, 3 MB/D will have accrued to OPEC.

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SLIDE #8: NEAR-TERM OPEC CRUDE REQUIREMENTS (continued)

o However, the rate of growth is clearly slowing down, and along with it the rate at which the call on OPEC is growing. After 3.5% growth in 1988, demand this year is expected to be up only about 2%. Given the economic environment I described at the start of my remarks, we see that pace slowing yet again in 1990 to 1.5%.

o On an annual basis, actual OPEC production does not seem all that far out of line with demand. OPEC production was less than total requirements in 1987, about in line in 1988, and is projected to be only slightly above total requirements this year. Unfortunately for those who would prefer higher prices, however, OPEC production is well above the theoretical quota (19.5 MB/D through the third quarter). Moreover, the pattern has been one of steadily rising production throughout the year (Q1 20.2 MB/D; Q2 21.2 MB/D, Q3 22.0 MB/D, currently estimated at *22-22.5 MB/D.)*

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SLIDE #8: NEAR-TERM OPEC CRUDE REQUIREMENTS (continued)

- If production stays *much above 22* MB/D in Q4, and continues at that pace through Q1 1990, Q1 inventories would increase rather than decline as they customarily do in the quarter. Whether or not the increase would be enough to push down prices is an open issue, but it clearly has to be a concern.

- Of course if production were to *drop below 22 MB/D,* (down to the supposed new quota level of 20.5 seems very unlikely), or if demand growth were to be more rapid than we project, the near-term situation would change very significantly.

SLIDE #9: PRINCIPAL UNCERTAINTIES

- One obvious uncertainty, then, is the rate of growth in demand. In this regard, the U.S. is undoubtedly the most important demand region. As I noted at the start, our outlook assumes a continuation of modest growth in the U.S. Were a recession to occur, the call on OPEC would fall, rather than rise, and there would likely be at least short-term downward pressure on prices. Conversely, if even a slowdown fails to occur, and the U.S. economy continues to grow at 2.5-3%, what now looks like OPEC overproduction would probably be readily absorbed by the market.

- On the supply side, OPEC is going through a transition period. Demand for its crude has grown rapidly, but the organization has not been able to agree on an orderly means of supplying that growth, and market share among members continues to be a source of friction. Contrary to earlier expectations, this friction has not diminished with higher volumes, and there seems to be no obvious analytical framework that would help identify a production level satisfactory to all participants. Overall, there seems to have been some shift to a market share orientation within the key OPEC members. How long this will continue is diffucult to project.

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SLIDE #9: PRINCIPAL UNCERTAINTIES (continued)

- As a result of this competition for market share, more capacity expansions may take place. Iraq is in the process of expanding capacity and other Middle East countries have proposed their own additions. To date, talk of additions has outpaced real activity but significant additions are technically achievable. OPEC does not seem to have a mechanism for deciding on capacity additions, but as with production, significant capacity expansions may occur.

- In light of the above, there is little reason to expect that the price volatility that has characterized the past four years will disappear any time soon. Apparently we are condemned to continue to live in interesting times for at least a few more years!

Thank you.

ECONOMIC UNDERPINNING

- FREE WORLD LONG TERM GROWTH RATES (1988-2010)

POPULATION	GNP	ENERGY USE
1.6%/YR	2.6%/YR	1.4%/YR

- NEAR TERM CONDITIONS

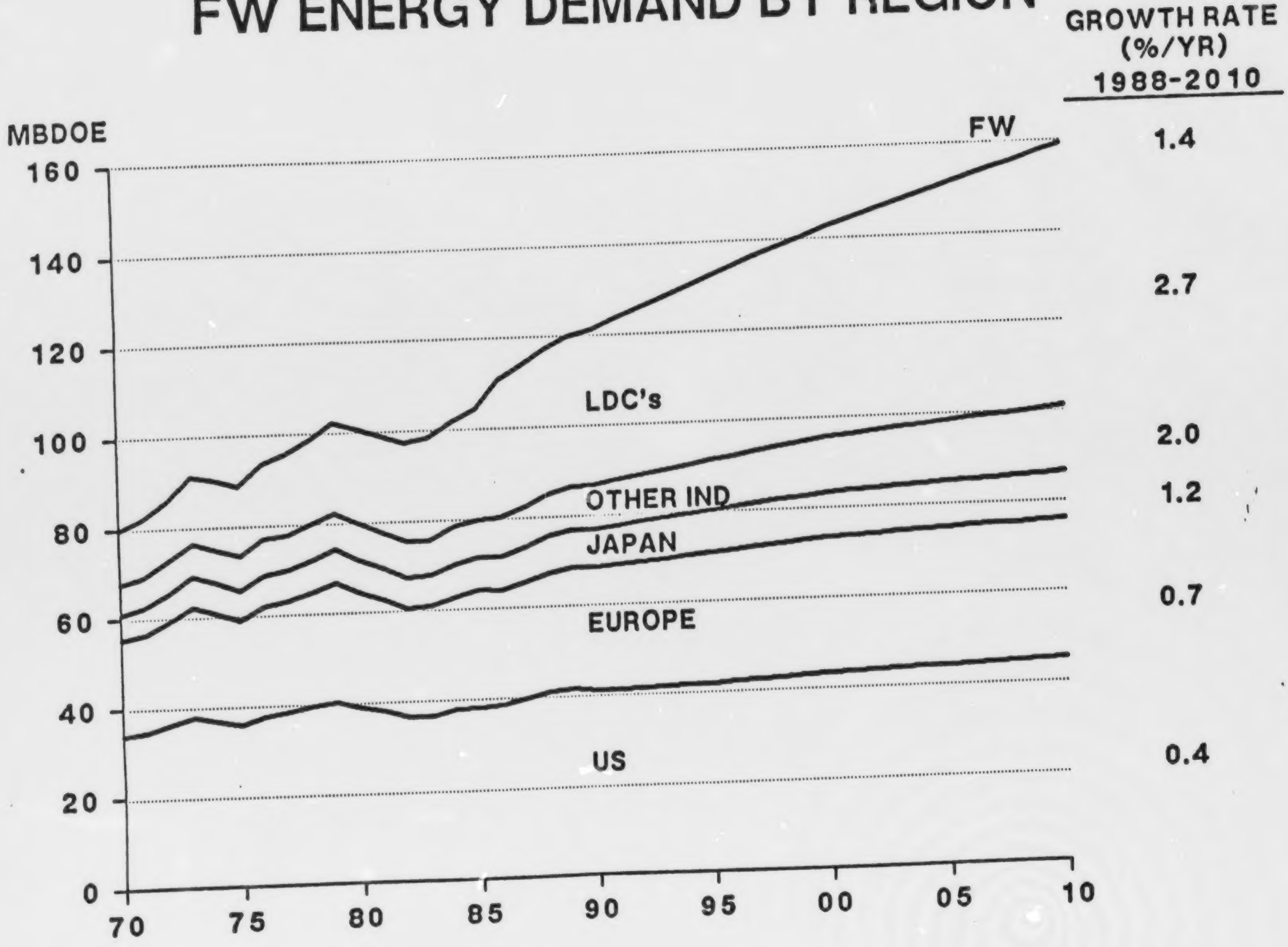
- U.S.	SOFT LANDING
- EUROPE	1992 A PLUS
- JAPAN	ECONOMY BOOMING
- LDCs	DEBT CRISIS EASING/FAR EAST BOOM

FW ENERGY EFFICIENCY TRENDS

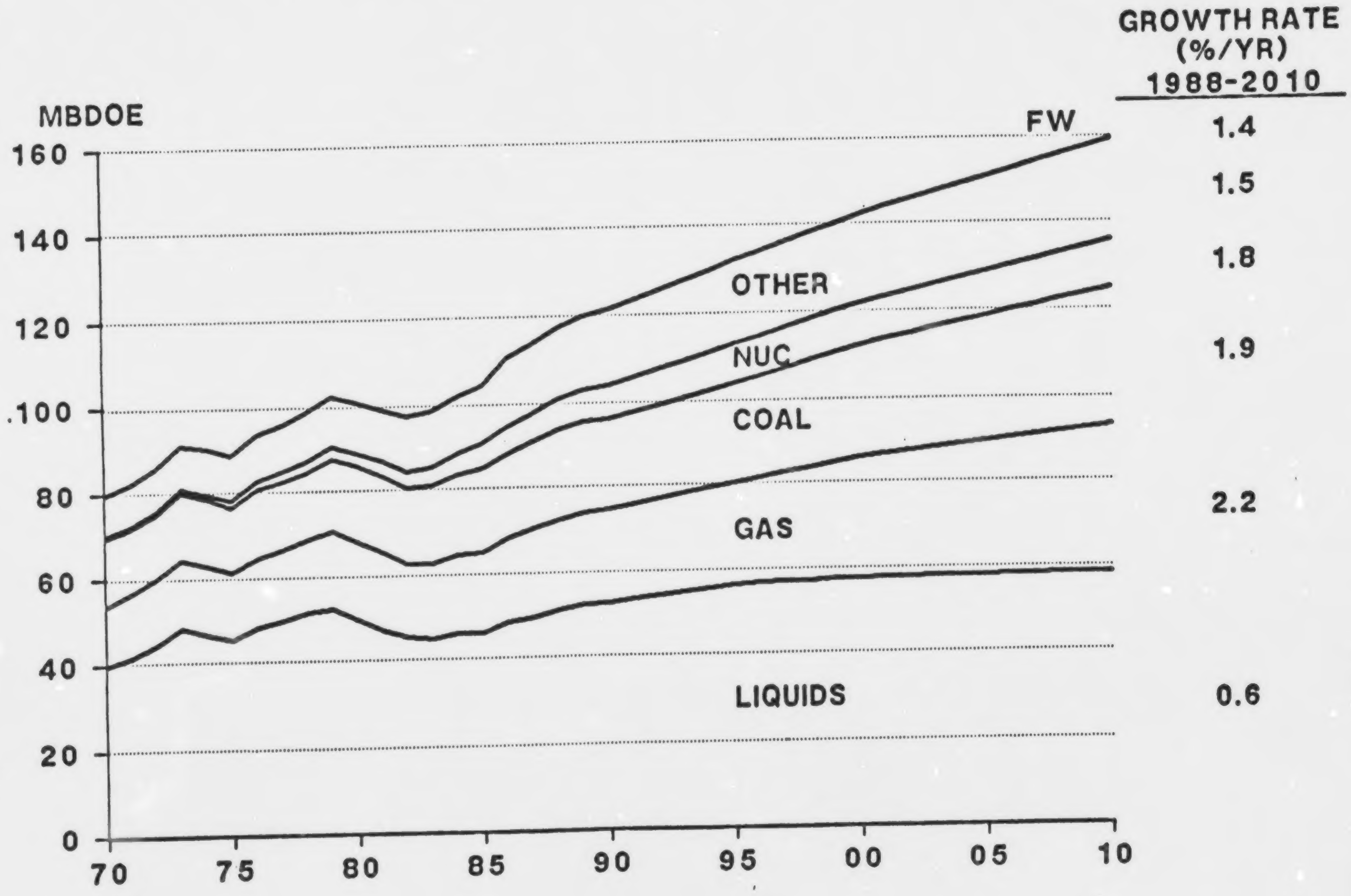
AVERAGE ANNUAL GROWTH RATES

	GNP	ENERGY USE	EFFICIENCY GAIN
1960 - 1973	5.0	5.4	(0.4)
1973 - 1985	2.7	1.1	1.6
1985 - 1988	3.5	3.0	0.5
1988 - 2010	2.6	1.4	1.2

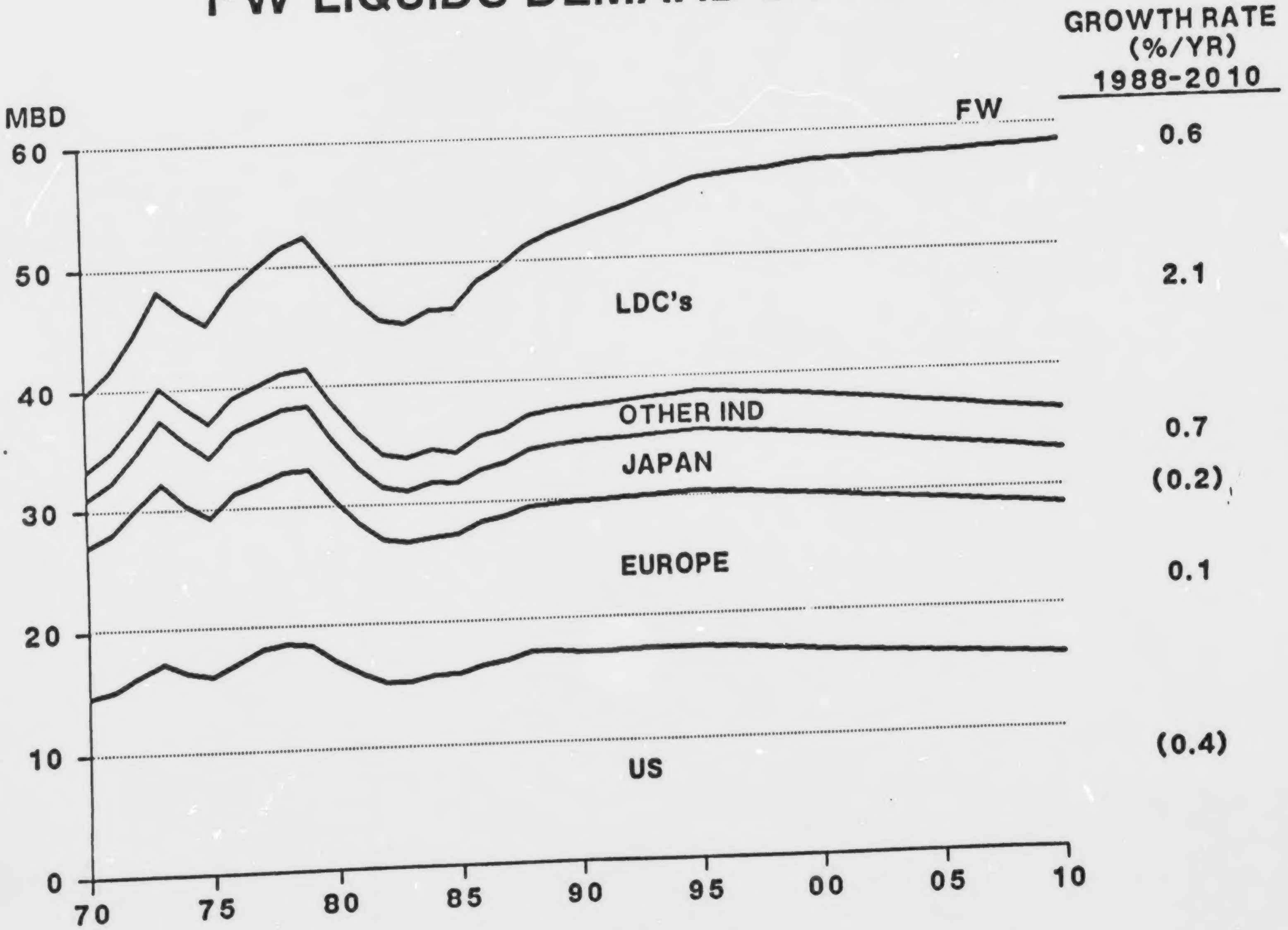
FW ENERGY DEMAND BY REGION



FW ENERGY DEMAND BY FUEL

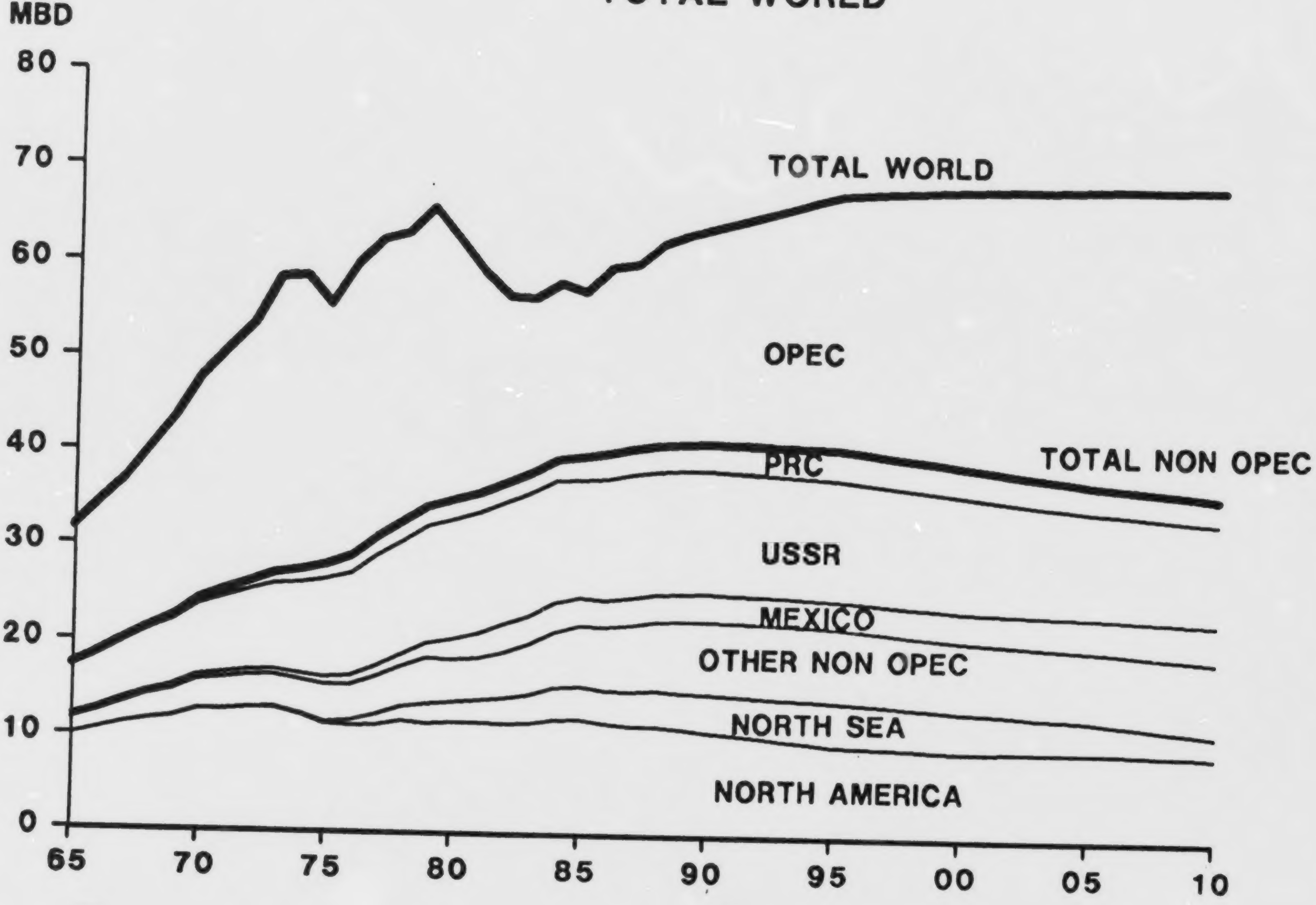


FW LIQUIDS DEMAND BY REGION



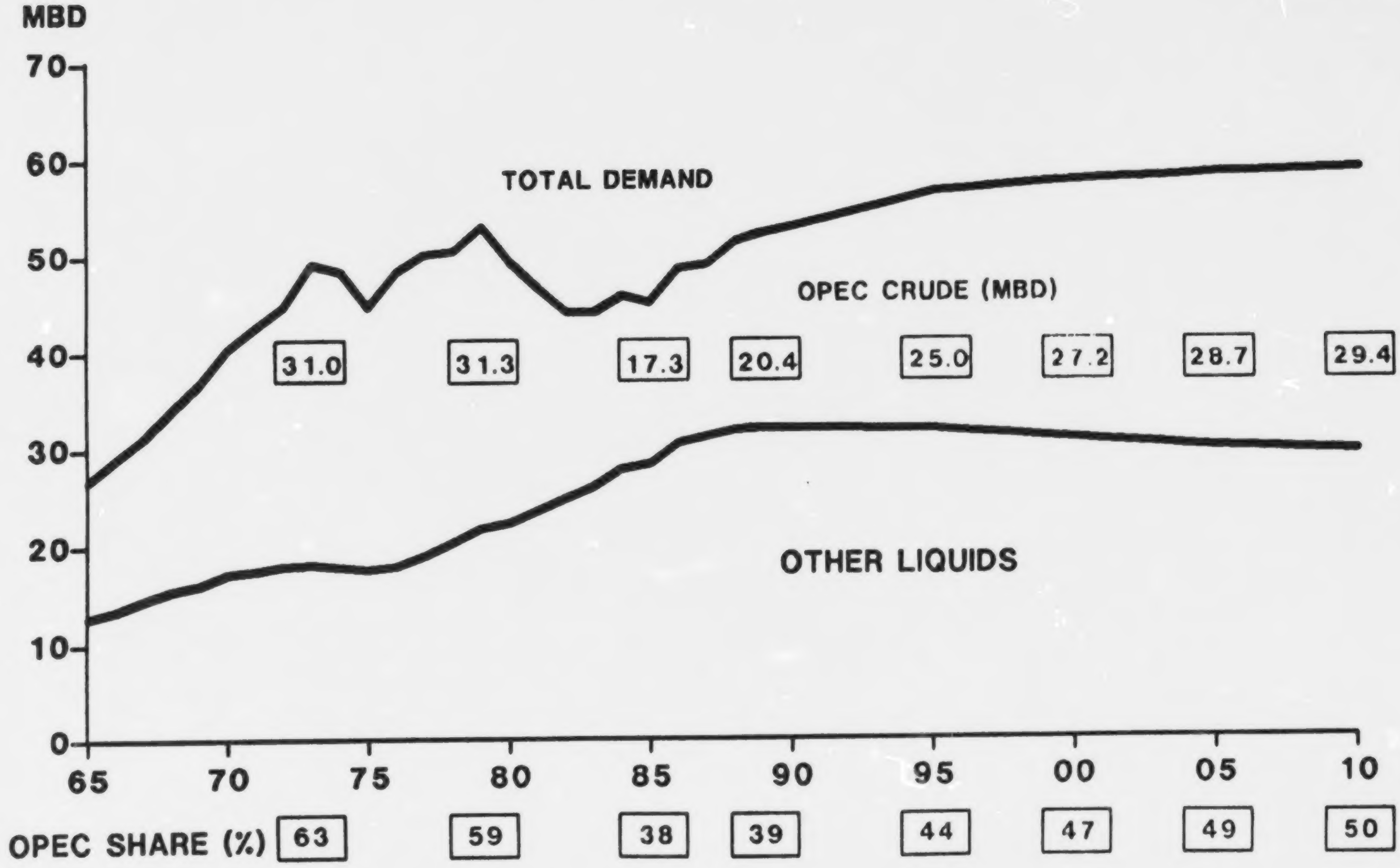
LIQUIDS PRODUCTION

TOTAL WORLD



POTENTIAL DEMAND FOR OPEC CRUDE

FREE WORLD



OPEC CRUDE REQUIREMENTS

			FORECAST	
	1987	1988	1989	1990
DEMAND	49.5	51.3	52.3	53.1
SUPPLY				
NON-OPEC CRUDE	22.7	22.7	22.6	22.9
OTHER	8.4	8.6	8.7	8.8
OPEC CRUDE REQUIREMENT	18.4	19.9	21.0	21.4
ACTUAL OPEC PRODUCTION	17.8	19.9	~21.3	

PRINCIPAL UNCERTAINTIES

- RATE OF GROWTH IN DEMAND
- DURATION OF KEY COUNTRIES' MARKET SHARE/VOLUME ORIENTATION
- PACE OF OPEC CAPACITY EXPANSIONS

MEDIUM TERM SUPPLY AND DEMAND OUTLOOK

PRESENTED BY

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EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
CALGARY, ALBERTA
OCTOBER 22-24, 1989

ECONOMIC STRENGTH

THE STRENGTH OF THE WORLD ECONOMY, ESPECIALLY THE ECONOMIES OF THE LEADING INDUSTRIALIZED NATIONS, REPRESENTS AN IMPORTANT FACTOR IN THE ASSESSMENT OF FUTURE OIL TRENDS. THEREFORE, BEFORE ANALYZING THE INTERNATIONAL OIL MARKET, WE MUST FIRST TURN OUR ATTENTION TO THE MORE GENERAL QUESTION OF THE WORLD ECONOMY.

WORLD ECONOMIC GROWTH, WHICH HAD BEEN JUST OVER 2.5 PERCENT SO FAR IN THE 1980's, HAS AVERAGED 3.5 PERCENT DURING THE LAST THREE YEARS.

THE GENERAL CONSENSUS IS THAT UNLESS THERE IS A SERIOUS ECONOMIC RECESSION, THE AVERAGE WORLD ECONOMIC GROWTH RATE OVER THE NEXT YEARS WILL BE AT LEAST 2.5 PERCENT, WITH EVEN 3.3 PERCENT A POSSIBILITY. THE INDUSTRIALIZED COUNTRIES HAVE BEEN SUCCESFUL IN KEEPING INFLATION UNDER CONTROL, AS WELL AS MANAGING POTENTIAL ECONOMIC RECESSION.

THE GROWTH OF PETROLEUM DEMAND

PETROLEUM DEMAND WHICH HAD BEEN STAGNANT DURING THE FIRST HALF OF THE 1980's, RESPONDED FAVORABLY TO THE NEW COMPETITIVE PRICE LEVELS, AS WELL AS TO STRONGER ECONOMIC GROWTH. PETROLEUM DEMAND HAS INCREASED BY OVER 1 MMBD IN EACH OF THE LAST THREE YEARS. TWO YEARS AGO WAS AN ALL BUT UNANIMOUS CONSENSUS THAT DEMAND WOULD STABILIZE THROUGH THE END OF THIS CENTURY.

THIS YEAR DEMAND (EXCLUDING CPE'S) WILL APPROXIMATELY EQUAL TO ITS PREVIOUS ALL-TIME HIGH OF 51,3 MMBD REACHED IN 1979.

BUT THE DEMAND IS VERY DIFFERENT, WITH A MUCH LIGHTER BARREL. FUEL OIL'S SHARE OF THE MARKET HAS DROPPED FROM 25% IN 1979 TO 16% THIS YEAR; GASOLINE AND MIDDLE DISTILLATES HAVE RISEN FROM 60% TO 67%. FUEL OIL HAS BEEN TO SOME EXTENT REPLACED BY COAL, AND MORE GASOLINE IS BURNT.

A CONSENSUS NOW SEEMS TO BE FORMING THAT IN THE MEDIUM TERM, WORLD OIL DEMAND WILL GROW AT ABOUT 2.0% PER YEAR, PACED BY THE FAR EAST, WHERE THE MAJORITY OF GROWTH IS OCURRING. FOR EXAMPLE, THE SOUTH KOREAN OIL DEMAND GROWTH 17% IN 1988 AND 1989. LIKEWISE, THAILAND (+13% IN 1988 AND +15% IN 1989), AND MORE RECENTLY PHILIPPINES (+ 13% IN 1989).

NON-OPEC

NET NON-OPEC PRODUCTION HAS REACHED A PLATEAU: NON-OPEC SUPPLIES REMAIN STAGNANT OVER THE NEXT FEW YEARS.

NON-OPEC ARE COOPERATING TO MAINTAING MARKET STABILITY: SEVERAL OF THE IMPORTANT NON-OPEC OIL PRODUCING COUNTRIES HAVE COOPERATED INCREASINGLY WITH OPEC MEMBERS IN THEIR EFFORTS TO ACHIEVE MARKET STABILITY. THE PRESENT POSITIVE MOOD RESULTING FROM THIS COOPERATION HAS BEEN A SIGNIFICANT FACTOR IN FIRMING UP OF PRICES IN THE WORLD OIL MARKET DURING THIS YEAR.

HOWEVER, IN THE MEDIUM TERM, TO MAINTAIN MARKET STABILITY OPEC MEMBERS BURDENED WITH SIGNIFICANT EXCESS CAPACITY WILL CONTINUE TO REQUIERE EFFECTIVE SUPPORT FROM THE NON-OPEC GROUP.

THE MEDIUM TERM UNCERTAINTIES ARE GENERALLY FAVORABLE FOR OPEC

POSITIVE INFLUENCES:

+ NON OPEC: ACCIDENTS HAVE RESULTED IN NET PRODUCTION FALLING BELOW EXPECTED CAPACITY.

+ ENVIROMENTAL PRESSURES:

  - DELAYS IN STARTING UP NEW PRODUCTION (EG. OFFSHORE CALIFORNIA); AS WELL AS EFFORTS TO IMPROVE SAFETY (EG. NORTH SEA), MAY RESULT IN LOWER DOMESTIC PRODUCTION.

  - DELAYS IN STARTING UP NEW NON-OIL POWER STATIONS (NUCLEAR, COAL), WILL TEND TO INCREASE DEMAND FOR OPEC OIL: DEMAND FOR ELECTRIC POWER WILL KEEP GROWING FOR THE FORESEABLE FUTURE. IF COAL AND NUCLEAR POWER ARE EXCLUDED FROM SUPPLYING THE FUELS FOR THIS GROWTH, OIL AND GAS WILL HAVE TO FILL DE GAP.

  - MORE STRINGENT PRODUCT QUALITY SPECIFICATIONS, MAY RESULT IN HIGHER REFINERY FUEL USE.

+ FUTURE U.S. NATURAL GAS SUPPLY IS UNCERTAIN: AFTER YEARS OF LOW DRILLING ACTIVITY FUTURE U.S. GAS SUPPLY IS UNCERTAING AND OIL IMPORTS COULD BE NEEDED TO FILL THE ENERGY GAP.

+ CPE's: INNER TURMOIL MAY LOWER PRODUCTION AND ECONOMIC LIBERALIZATION MAY RESULT IN HIGHER LOCAL DEMAND. TWO OUTCOMES THAT MAY REDUCE EXPORTS. THE QUESTION WOULD BE USSR AND CHINA, WHICH ARE IN TRANSITION.

+ FAR EAST OIL DEMAND: MAY CONTINUE TO EXCEED EXPECTATIONS.

NEGATIVE INFLUENCES:

- RECESSION: WOULD TRIM DEMAND GROWTH BUT A POTENTIAL RECESSION IS LIKELY TO BE LESS SEVERE THAN IN 1974 AND 1982.

- CONSUMPTION TAXES: ANY CONSUMPTION TAXES (ENVIRONMENTAL, CONSERVATION, NATIONAL SECURITY, BUDGET CONSIDERATIONS), WOULD ALSO LOWER DEMAND.

IF DEMAND CONTINUES TO GROW, AND NON-OPEC SUPPLIES STAY FLAT, DEMAND FOR OPEC OIL WILL INCREASE STEADILY.

IF DEMAND FOR OIL GROWS AT 2% PER YEAR, NEAR RECENT RATES, AND NON-OPEC SUPPLIES REMAIN STAGNANT, DEMAND FOR OPEC OIL IS PROJECTED TO BE AROUND 29 MMBD BY 1995 AND ABOUT 35 MMBD BY 2000. ASSUMING A REQUIREMENT OF 8% SPARE CAPACITY FOR THE MAINTENANCE OF NORMAL OPERATIONS, OPEC WILL NEED A CAPACITY OF 31 MMBD BY 1995, AND 37 MMBD BY THE YEAR 2000. THIS WILL REQUIERE OPEC TO CREATE AT LEAST 10 MMBD OF ADDITIONAL PRODUCING CAPACITY BY THE END OF THE CENTURY. IF THE DEMANDS FOR OIL GROWS AT 3% PER YEAR, OPEC WILL NEED TO CREATE AROUND 19 MMBD OF ADDITIONAL PRODUCING CAPACITY BY THE YEAR 2000. THIS FACTOR INDICATES THAT SUBSTANTIAL CAPITAL WILL BE REQUIERED IN PRODUCTION DURING THE COMING YEARS.

IN THE REFINING SECTOR, THE FINANCIAL REQUIREMENTS NEEDED TO SATISFY A 2% TO 3% YEARLY DEMAND GROWTH ARE LIKEWISE IMPRESSIVE. AT THE SAME TIME, REFINERS FACE THE CHALLENGE OF ENSURING THAT THEIR PRODUCTS CONFORM TO INCREASINGLY STRINGENT ENVIRONMENTAL REGULATIONS. ACCORDING TO SOME ESTIMATES, BETWEEN 30% AND 40% OF THE INVESTMENTS IN THIS SECTOR DURING THE NEXT DECADE WILL BE DIRECTED TOWARDS MEETING ENVIRONMENTAL SPECIFICATIONS.

SUMMING UP, ENORMOUS AMOUNTS OF CAPITAL MUST BE RAISED TO FINANCE THE CAPACITY ADDITIONS IN THE PRODUCTION AND REFINING SEGMENT TO SATISFY DEMAND GROWTH. WHILE IT IS IMPERATIVE THAT OIL PRICES REMAIN COMPETITIVE TO SUSTAIN THE DEMAND REBOUND, SHORT-TERM GLUT-INDUCED PRICE COLLAPSES CAUSED BY OVERPRODUCTION REPRESENT A DIRECT THREAT TO THE LONG-RUN VIABILITY OF THE INDUSTRY.

VENEZUELA

PROVED RESERVES POSITION

ACCORDING TO INTERNATIONAL SOURCES, VENEZUELA HAS THE SEVENTH LARGEST PROVED RESERVE BASE IN THE WORLD. IN THIS HEMISPHERE, IT HAS THE LARGEST RESERVES, AND WITH A LOW DEVELOPMENT COST.

THE VENEZUELAN PROVED RESERVES ARE APPROXIMATELY 58.5 BILLIONS BARRELS, OR ABOUT 7 PERCENT OF THE WORLD'S PRESENT TOTAL PROVED RESERVES.

IN ADDITION TO THAT FIGURE, WE HAVE AN ESTIMATED 52 BILLION BARRELS OF CRUDE OIL THAT CAN BE MADE AVAILABE THROUGH THE APPLICATION OF SECONDARY RECOVERY TECHNIQUES AND EXPECTED NEW DISCOVERIES. IN ADDITION, APPROXIMATELY 236 BILLION BARRELS OF RECOVERABLE RESERVES OF HEAVY AND EXTRAHEAVY OIL ARE LOCATED IN THE ORINOCO BELT (WHICH CONTAINS 1,2 TRILLION BARRELS OF OIL IN PLACE). THUS, VENEZUELA'S TOTAL ESTIMATED RESERVES ARE ON THE ORDER OF 347 BILLION BARRELS.

THE YEAR-END 1988 REMAINING PROVED GAS RESERVES STAND AT 101 TRILLION CUBIC FEET OF NATURAL GAS.

VENEZUELAN OIL PRODUCTION CAPACITY HAS BEEN KEPT AT 2.6 MILLION BARRELS PER DAY BY MEANS OF INTENSIVE EXPLORATORY AND MAINTENANCE EFFORTS. THE CURRENT PRODUCTION IS ABOUT 1.8 MILLION B/D; HOWEVER, IF REQUIRED, THE PRODUCTION CAPACITY CAN BE REACHED WITHIN A VERY SHORT TIME SPAN.

RESERVE/PRODUCTION POSITION

THE VENEZUELAN TOTAL PROVED RESERVES TO PRODUCTION POSITION IS 94 YEAR, AT THE RATE OF 1.8 MILLION BARRELS PER DAY. THIS POSITION MORE THAN ADEQUATELY GUARANTEES A VERY HIGH DEGREE OF PRODUCTION STABILITY, AN IT COMPARES VERY FAVORABLY WITH THE POSITIONS OF THE WORLD'S MAJOR OIL PRODUCERS.

VENEZUELA CURRENTLY PRODUCES MUCH LESS OIL THAN COUNTRIES WITH FAR LESS RESERVES SUCH AS THE UNITED STATES AND THE SOVIET UNION. THIS OBVIOUSLY IMPLIES THAT VENEZUELA'S RESERVES COULD ADECUATELY SUSTAIN A MUCH HIGHER PRODUCTION RATE.

NEW LIGHT OIL DISCOVERIES

THE EXPLORATORY EFFORT OF RECENT YEARS HAVE BEEN CROWNED WITH SOME TRULY IMPRESSIVE LIGHT AND MEDIUM GRADE CRUDE OIL DISCOVERIES. THE EXPECTED ULTIMATE RECOVERY FROM THESE FINDS TOTALS 13.1 BILLION BARRELS OF OIL (LOW SULPHUR CONTENT).

THE LARGEST DISCOVERY WAS MADE IN NORTHERN MONAGAS WITH ULTIMATE RESERVES ESTIMATED AS HIGH AS 8.6 BILLION BARRELS. DEVELOPMENT OF THIS AREA IS UNDERWAY, AND IT SHOULD BE PRODUCING 500.000 B/D OF 26-33° API OIL BY YEAR-END 1994.

THE PER WELL OIL PRODUCTION RATES ARE QUITE HIGH, RANGING FROM 5.000 TO 15.000 B/D PER WELL.

ALL OF THESE DISCOVERIES ARE RELATIVELY CLOSE TO EXISTING INFRAESTRUCTURE WHICH PERMITS IMMEDIATE INCORPORATION TO THE PRODUCTION STREAMS.

BECAUSE OF THE HIGH WELL PRODUCTIVITY AS WELL AS THE USE OF EXISTING INFRAESTRUCTURE. THE DEVELOPMENT COST OF THESE FIELDS IS RELATIVELY LOW.

IN ADDITION TO THIS FIND, PRELIMINARY GEOLOGIC INTERPRETATIONS AND EXPLORATORY DRILLING HAVE INDICATED THAT LARGE LIGHT AND MEDIUM GRAVITY OIL RESERVES ARE TO BE CONFIRMED IN NORTHERN ANZOATEGUI, SOUTH LAKE MARACAIBO, AND IN THE CRETACEOUS FORMATIONS IN CENTRAL LAKE MARACAIBO.

FURTHERMORE VERY LARGE VOLUMES OF LIGHT AND MEDIUM OIL RESERVES ARE EXPECTED TO BE FOUND UNDER THE ANDEAN FOOTHILLS IN WESTERN VENEZUELA AND IN THE NORTHERN ORINOCO DELTA REGION IN EASTERN VENEZUELA.

OTHER ASPECTS:

VENEZUELA HAS EXCESS DOMESTIC REFINING CAPACITY AND HAS INVESTED HEAVILY IN UPGRADING ITS REFINERIES TO YIELD A HIGHER VALUE PRODUCT MIX. AND TO MEET CHANGING MARKET CONDITIONS.

SINCE 1983, VENEZUELA MOVES INTO DOWNSTREAM INTEGRATION IN EUROPE AND THE UNITED STATES. INCLUDING THE LEASED REFINERY IN CURACAO, VENEZUELA NOW PROVIDES SOME 730.000 B/D TO AFFILIATED OVERSEAS VENTURES. THESE VENTURES GO FAR TOWARD MAKING PDVSA AND ITS AFFILIATES INTO AN INTEGRATED INTERNATIONAL OIL COMPANY WITH ITS OWN PRODUCTION MULTI-COUNTRY REFINING, AND MARKETING SYSTEM.

WHEN COMBINED THOSE OVERSEAS VENTURES WITH VENEZUELA'S OWN UPGRADED EXPORT REFINING CAPACITY, TOTAL REFINERY CAPACITY AMOUNT TO 1.700.000 B/D. THIS MAKE VENEZUELA INTO PRIMARILY A SELLER OF REFINED PRODUCTS.

CERTAIN CONSIDERATIONS AFFECTING THE WORLD OIL MARKET

Presented by

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1. Energy Projections

The most troubling aspect of projections of supply and demand, even over a six-month term, is the difficulty faced by energy analysts in determining likely growth rates in energy demand generally and for oil in particular. The trouble begins with the most important measure of all -- GNP growth. Without a close approximation of this measure, no reliable calculation of energy demand is possible. We should be reminded of this time and again as projections of basic economic progress are revised, sometimes fundamentally, against the requirement for a reliable measure to encourage large, long-term investments.

The only dependable indicators of economic change pertain to the OECD member states whose statistical compilations are the most thoroughly prepared and analyzed. As a general rule, no developing country matches the efforts of the industrial democracies in terms of data reliability. Yet, as we have seen even in the case of the United States, projections of GNP are issued and then soon revised up or down by significant amounts, almost as a matter of course. For 1989, for example, we have had projections of U.S. GNP growth between 1.5-3.5 percent -- a staggering wide range with enormous implications for all economic sectors including energy.

For most of the OECD, annual average GNP growth is thought to be about 2.5-3.0 percent for the next five years. Within that range, energy growth is cited often at an annual average of perhaps 2.0 percent and oil's growth rate at between 1-2 percent per year. How this translates into millions of barrels of oil depends most basically on the accuracy of GNP projections.

There is nothing that any one of us in this room can do about this situation. For example, the International Energy Agency (IEA) makes the most careful effort to improve on energy data and projections but almost every quarter it corrects what has been declared as its best data and forecasts. It is not a result of carelessness; it is the result of constantly having to try and improve upon the data the IEA receives.

Data on the supply situation are subject to different kinds of errors. Prior to 1973, oil supply numbers were widely regarded as reliable -- they came almost entirely from private sector oil companies, the oil "majors."

Since then, as OPEC governments took over the responsibility of providing most supply data, there has been a severe loss in data credibility. We do not know -- have no way of verifying -- production data from OPEC. At any moment, total real barrels may be off from OPEC country figures by 1-3 MMB/D. Governments have all kinds of reasons for wanting to conceal true figures; some of these reasons have to do with today's fragile formula of quotas; other have to do with political and security relationships between Gulf producers; others have to do with efforts by other members -- such as Venezuela -- to use definitions of crude and condensate which suggest ways of evading its quota; still others -- such as Nigeria, Saudi Arabia, and several others -- try to avoid quotas as generally understood by suggesting the "leasing" of barrels. Also, products are not yet counted against quotas. There seems to be no end to their ingenuity.

On several occasions OPEC has adopted measures to "police" production data. Time and again these efforts have been rendered meaningless by the outright refusal of a number of OPEC members to comply.

In fact, supply data from only a few significant producers are dependable: Canada, the United States, Britain, Norway, Australia, and Malaysia, perhaps a few more, but that is it. The indications we have that the "errors" in reporting supply data may not be more than 1-3 MMB/D lies in the relative stability and transparency of oil prices. Even though we do not know -- can only guess for the most part -- if the destination of many of those "invisible" barrels is land or sea storage, or whatever.

These matters are of greater concern to those whose time horizon is short. For the true investor, whose basic data begins with the GNP, there is a widespread assumption that oil demand growth will continue. In OECD economies, it will be a general annual average of 1-2 percent; among developing countries, it will reach a general annual average of 2-4.0 percent or even more for the next five to ten years. For some of these investors a major question is the extent to which OPEC unity is maintained and thus its price for oil.

The challenge to OPEC is clearly to reverse the trends of the past decade which resulted in lower consumption of oil in the OECD in 1988 (and 1989) than in 1979, and in large increases in the competing fuels. In that period, demand for coal rose by 23 percent and natural gas by 27 percent. See the following table.

But the competition for different fuels will be won not only by the oil price but by actions of importing, consuming nations which have options beyond oil. If one could anticipate that in the years ahead, OPEC prices would be determined by regional markets, as has now begun to be the case, then the likelihood of OPEC attempting again to act like a traditional cartel would be of much less concern. But it is much too soon to think this will be the case, desirable as it would be.

WORLD: PRIMARY ENERGY CONSUMPTION[a]
(Million tonnes oil equivalent)

	1979	1986	1987	1988	% Share 1988	% Change Over '87	1988 Over '79
By Type							
Oil	3142	2905	2948	3038	38	+3.1	-3.3
Coal	1968	2263	2342	2428	30	+4.7	+23.4
Natural Gas	1283	1487	1552	1625	20	+3.7	+26.7
Hydro	424	517	525	528	7	+0.5	+24.5
Nuclear	156	377	406	439	5	+8.0	+181.4
Total	6972	7548	7774	8058	100	+3.7	+15.6
By Area							
N.America	2136	2040	2099	2192	27.2	+4.5	+2.6
W.Europe	1294	1280	1289	1302	16.3	+1.0	+1.4
Japan	370	372	377	400	5.0	+6.2	+8.1
Australasia	83	97	103	107	1.3	+3.6	+28.9
Total OECD	3883	3789	3868	4001	49.8	+3.4	+3.0
Rest Free World	874	1175	1240	1312	16.2	+5.8	+50.1
Total Free World	4757	4964	5108	5313	66.0	+4.1	+11.7
Communist Bloc	2215	2581	2666	2745	34.0	+3.0	+23.9
WORLD TOTAL	**6972**	**7548**	**7774**	**8058**	**100.0**	**+3.7**	**+15.6**

(a) Commercially traded fuels only.
Source: British Petroleum Company, cited in Petroleum Economist, August 1989, p. 243.

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2. The Question of OPEC Unity

Over the next several decades, the most important question to keep in mind is the prospect of OPEC unity. A number of analysts have stated that when OPEC supply reached 80 percent of its members' productive capacity, "oil power" to determine prices will again belong to OPEC. Today, OPEC's capacity to produce probably amounts to some 29 MMB/D. In the past several months, OPEC has supplied that magical 80 percent or somewhat over 22 MMB/D; OPEC "oil power," which implicitly assumes cartel unity and quota discipline, has been conspicuously absent.

"OPEC oil power" depends largely on the ability of Iran, Iraq, and Saudi Arabia to agree on a durable oil policy and practice to control their production for export to achieve agreed price objectives or to secure for themselves a fixed share of the OPEC crude market. In the case of Saudi Arabia, that share is currently about 25 percent; for Iraq, it is 14 percent. Currently these two are the only OPEC members with large (and growing) producing capacities. Iran is producing near capacity for export but has to be included along with Saudi Arabia and Iraq for reason of its geopolitical significance.

An agreement between these three countries implies understandings which include more than their economic or financial interests, it implies broader undertakings regarding their political and security objectives with respect to each other. How these are worked out, if at all, will have great influence over prices and the stability of the world oil market. But even if their relationships can be agreed to, and the price of world oil is defined accordingly, the growing issue remains as to why Indonesia, Nigeria, and Venezuela, among others, should continue to accept an oil price definition which reflects the Middle East Gulf's political, security, and financial issues. Most of these issues have nothing whatever to do with the concerns and objectives of all other OPEC members. One can argue that if the Gulf-defined world oil price is rising, it will bring along with it the interests of the rest of the cartel. Perhaps, but increasingly, there are signs of restiveness among its members: The price today is not high enough, or it does not reflect real market conditions in key consuming areas; or the definition of the price does not take sufficiently into account the threat from alternative fuels, especially natural gas, etc. More recently, another basic issue for OPEC cooperation has been the fact that several of its key members have been emphasizing product sales, not crude, and are making significant downstream investments in major consuming markets.

Nor must we assume that OPEC "learned its lesson" in the sudden, very large price increases of the 1970s. Today, is its unity to be assumed as it produces more nearly at its current potential with an ever-larger share of world production -- now 35 percent -- (or over 75 percent of oil in international trade)?[1] Also is it possible that non-economic forces, acting on the key suppliers of the Gulf, will serve to weaken the cartel, irretrievably?

Over the next decade, it seems obvious that OPEC's greatest difficulty lies in (1) obtaining agreement as to how quotas will be set, and (2) whether cartel discipline can be applied to those who disregard their allocation. It is my view that neither of these conditions can be met so the other question is still the interest of major producers (Saudi Arabia, Iraq, Kuwait, UAE) to continue to make adjustments in their own output to keep OPEC's supply within an agreed total. I do not believe this will happen.

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[1] OPEC crude production estimated at 22 MMB/D. Domestic consumption at 4 MMB/D; 18 MMB/D into international trade. Non-OPEC crude exports estimated at 6.3 MMB/D.

OPEC CAPACITY, QUOTAS, AND PRODUCTION ESTIMATES
(MMB/D)

	90-Day Capacity	New Quota	September Production	% Over Quota	% Under Capacity
Algeria	0.75	0.770	0.70	-9	-7
Ecuador	0.33	0.225	0.30	18	-9
Gabon	0.27	0.184	0.23	25	-15
Indonesia	1.30	1.374	1.20	-13	-8
Iran	3.40	2.925	2.90	-1	-15
Iraq	3.85	2.925	2.90	-1	-25
Kuwait	2.50	1.149	2.00	74	-20
Libya	1.20	1.149	1.10	-4	-8
Nigeria	1.80	1.501	1.70	13	-6
Qatar	0.60	0.346	0.40	16	-33
Saudi Arabia	8.80	5.013	5.10	2	-42
UAE	2.00	1.095	2.00	83	-0
Venezuela	2.20	1.813	1.75	-3	-20
TOTAL	29.00	20.500	22.28	9	-23

Sources: International Energy Agency and Petroleum Intelligence Weekly, U.S. Central Intelligence Agency, County NatWest USA/Washington Analysis; cited in Monthly Oil Highlights, County NatWest USA/Washington Analysis Corporation, October 4, 1989.

Nor need we assume as many do that non-OPEC suppliers have reached a production plateau from which their contribution to world supply will inevitably decline, giving more and more of the advantage to OPEC. It is held today to be almost a "fact" that the United States, Canada, the North Sea, and now the Soviet Union are entering into an irreversible decline. Yet we have all been surprised at the continuing investments in these areas, and in other parts of the world, and in the results achieved through new technologies which increase expectations of greater recovery from existing fields.

Nor can we assume that governments of oil importing countries will accept ever-greater dependence on oil. Developing countries may conclude they have no choice. It is possible that by far the greater part of increased demand for OPEC oil will come from LDCs (3.75 percent in 1989)[2], and from growing U.S. imports, not from the OECD generally whose imports may not increase more than half of one percent annually for the next decade. The most significant force changing that OECD outlook could come from the greater environmental impact of coal consumption leading to greater oil use.

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[2] Source: Petroleum Economics, Ltd.

3. Government Intervention on Price?

We should anticipate that if OPEC unity is achieved (and the price goes up), or if the oil price is lowered (to reduce OECD investments into alternative fuels, and to cause OECD exploration efforts to decline still further), governments will intervene with various domestic price support measures or other fiscal incentives as has happened in the not-so-distant past in Canada, in the United States, in the North Sea, in France, and in Japan. The latter two emphasized the nuclear option.

The argument will again be brought forward: When a nation possesses large energy resources, should it allow foreign governments to define the price of international and domestic oils and thereby determine whether or not domestic exploration and production will take place? Or will a nation allow others to determine whether exploitation of its other energy resources (whose price is linked to that of oil) will or will not take place? Time and again in order to protect themselves from cheaper, foreign oil with all its economic, financial, and security implications, one sector or another of the U.S. oil industry has argued this way, as has the oil industry or governments of other countries.

When governments have intervened in the past thirty years, the end-results have been disappointing to the consumer or the industry but that record has never discouraged one sector or another from trying it again, sometimes with the encouragement of their governments. The question will still be on the table: Does acceptance of an OPEC price determine our energy future? Unfortunately, for the credibility of the interests engaged, when the oil price was soaring, very very few in the industry warned that it was governments (OPEC) which were establishing the new and higher levels. But let the price fall, then the warnings about an OPEC cartel are heard. As the United States imports more than 50 percent of its oil demand (as has begun to happen) and as Canada confronts the findings of the Canadian Energy Research Institute's (CERI) study of the nation's crude oil prospects -- Canadian Crude Oil: Supply/Demand Balances -- the case will be made that policies need to be established, once again, to preserve our respective energy options against foreign supplies.

4. A Definition of Price

We could argue endlessly over what oil price would bring about investments into the exploration and development of all qualities of crude, in frontier areas, and into the more costly natural gas resources (such as Alaskan gas). Were I asked to define a domestic floor price I would propose $25/barrel to be increased by the rate of inflation. That price should meet the most costly of endeavors on the conventional oil (and gas) scene.

One way or another, I have been involved in every supply emergency since the Suez crisis of 1956, so I am fully aware of the difficulties involved in setting any price through government processes. Moreover, for the United States at least, I will remain concerned how the Congress always expands upon the legislation required: Remember the tortuous complexities of U.S. import programs beginning with the Eisenhower administration and continuing through that of Carter or the 1978 Natural Gas Act? I still think a floor price could be accepted publicly if a President put the full weight of his office into the political balance, and did so in concert with key leaders of the Congress. This has never happened.

The great difficulty in this or any price higher than today's average OPEC price of about $17/barrel is the understandable reluctance of investors to commit resources when any U.S. government assurance of price support will be vulnerable every two years at least to a political change in Congress, or every four years to a change in administration. There can be no long term assurance of stable policy. I have no answer to this defect in the American political system other than that at some time it will have to be addressed. How different has been the Canadian experience?

5. The Question of Conservation/Alternative Fuels

Virtually ignored in projections of energy demand is the issue of conservation: How much may yet be achieved, and with what consequences upon oil demand?

In the 1970s and early 1980s a large, but indefinable share of the decrease in oil demand was due to the consequences of price surges, and another share of the decline in oil consumption was due to the actions by energy consumers and governments leading to the selection of alternative fuels for a wide range of reasons, including concerns about security of oil supply.

We know now how very large an effect conservation or fuel-switching had on oil demand. (We know also how important has been the search for new non-OPEC oil sources -- as much as 6 MMB/D over the decade.) Between these two imperatives, demand for OPEC supplies fell since 1980 from 30 MMB/D to about 22 MMB/D.

While it is extremely difficult even to guess at further conservation/fuel switching results, we have to note:

(1) The new emphasis on reduction of emissions focuses largely on improvements in transportation fuels and in power generation. It seems altogether clear that the options today are for natural gas in some form in both sectors. The political sway of the environmental movement appears to be stronger (and more

durable?) than was ever anticipated, among OECD nations and increasingly among other societies. We may even be about to see a change toward the nuclear option.

(2) These changes in fuel options may not include coal unless (a) its emissions are further reduced, and (b) conversion processes become more economic. For the next decade, oil is still likely to dominate in transportation and become more attractive in power generation. But oil's future over the next several decades, once almost taken for granted, could be greatly diminished in those markets where natural gas is available in increasing volumes and where R&D into both gas and coal offers an increasingly attractive alternative, especially in transportation.

It is impossible to quantify how large these changes in fuels could be, or how soon they will take place. But some assert that out of these environmental concerns will come significant changes in oil demand in the OECD, and national energy policies will reflect domestic political imperatives undreamed of only several years ago. In fact, in countries such as the United States, definitions of a National Energy Policy may well emerge out of environmental concerns, less so from economic or security imperatives.

* * * * *

The European Natural Gas Market

A Summary of a contribution to be given by Prof.dr. Peter R. ODELL, Director of the Centre for International Energy Studies, Erasmus University Rotterdam in the Session on International Gas Markets at the Eighth CERI International Oil and Gas Markets Conference, Calgary, Canada, October 22-24, 1989

1. Background

a. Setting aside national differences (and excluding the U.K. and Italy), the West European gas system has emerged from the production/transmission facilities and the organisational structures based on the Dutch Groningen field development since the mid-60s. It was basically a Shell creation working in partnership with Esso. Between them they enjoyed over 40% of the European oil products' market so did not wish low cost, plentiful Groningen gas to further undermine what was already a weak oil market. Thus a set of monopoly outlets (one per country or region) was created, usually with Shell and/or Esso involved, to handle gas transmission and distribution.

b. Only in the Netherlands was gas made available at a price low enough to enable it to compete in the base-energy market. Elsewhere, the monopsonistically determined build up of end-user prices from the monopolistically determined frontier base price generally restricted gas markets (especially in power generation and industrial users).

c. Subsequently all developments which could have changed the role of gas from being only a limited source of Western Europe's total energy requirements have been rendered largely ineffective by the strength of the Groningen system. The system has thus emerged largely unscathed from events as traumatic as the oil price shocks (which otherwise would have greatly stimulated the exploitation of Western Europe's own gas); the initiation and development of Soviet gas exports from the mid-70s (given that the exports depended on agreement with

Ruhrgas so that Soyuzgas export became, in effect, an associate member of the Club of the W. European supply and/or transmission companies) ; and from the development of Norwegian gas exports which were allowed only limited access to mainland markets by Ruhrgas and its fellow Club members.

d. The objectives and strategy of restricting gas supplies to limited high value markets was aided and abetted by Norway's policy of a deliberately slow exploitation of its resources (under the mistaken notion that gas kept in the ground was worth more than gas sold to the market). Successive Dutch governments also supported the limited-development approach over the period - until the mid-80s - when conditions were otherwise perfect for maximising Groningen and other Dutch gas production. Happily for the stability of the restrictive and orderly marketing strategy, the system did not have to withstand any significant pressures from Algerian gas as the Algerians "shot themselves in the foot" by pricing their gas (f.o.b. Algerian port) to crude oil equivalent prices, so making it virtually impossible to market its gas in Western Europe.

e. EEC policy, based on an unsubstantiated belief in natural gas as a scarce resource (under the influence of the Club of Rome) played into the hands of the European gas establishment by directing that natural gas could not be used for power generation (for which, it argued, only coal and nucler power were to be used) and that its use should be discouraged for low value steam raising in industry etc.

2. Present Situation

a. As a result of the factors set out above, natural gas started as, and has since remained, an energy source of limited importance in Western Europe's energy markets (except in The Netherlands). As shown, institutional, pricing and regulatory reasons have all been involved. The system has a high degree of cohesion and solidarity and it still encompasses powerful forces (including governments, producers and transmission companies) which prefer to keep the system essentially unchanged : with the emphasis on technical efficiency, long-term supply/purchasing contracts, oil related pricing and the exclusion of low value markets ; and with little by way of entrepreneurial and innovative approaches to marketing the gas against competing sources of energy.

b. Such views persist in spite of the soft energy market in Europe, the opportunities for gas to compete against coal and nuclear power for power generation, and the now general acceptance that there are readily available supplies of much increased volumes of gas for the long-term. These factors are not collectively seen as a good enough reason by the gas industry for making dramatic changes to the previously agreed role of natural gas in the European energy system ; into which no new actors have been permitted to enter for well over a decade (except for institutions which work only or mainly at the national level, in, for example, Denmark and Spain).

3. The Prospects

a. There are currently only the merest of hints of internal instability in the Western European gas system : mainly the result of competition between suppliers for relatively stagnant markets - especially since 1986 with more attractive oil prices, a growing availability of low-cost imported coal, and more competitively priced electricity in end-uses where it is an alternative to gas. Even the potentially de-stabilising 1988 Statoil/SEP agreement, in which Norwegian gas was to be sold directly to the Dutch generating companies at a coal related price, has been brought within the framework of existing policies and organisational structures and has thus been prevented from setting a precedent.

b. Thus, all relevant governments and state owned/regulated (production)/transmission/(distribution) entities still hold to an outlook for natural gas which shows little essential change from the pattern established over the last 20 years : so that gas' share of the W. European energy market will remain at less than 20%, in spite of the continuing geographical expansion of gas availability. In essence, a much too comfortable club-like existence of the main actors whose profitability is virtually 100% guaranteed continues to minimise the motivation for change.

c. Thus, only the possible impact of other developments external to the gas industry and its present structure can introduce radical new elements. There are two such possibilities :

i. The Single Europe Act and its Implementation by the end of 1992 : the Commission believes this will undermine member states' exclusive rights over the transport, distribution and export/import of gas ; as well as requiring more price transparency ; and the creation of a more integrated infrastructure. This is a significant "political impetus", but the Commission's "information deficit" on relevant gas matters, plus serious doubts whether Community law on the free movement of goods and on competition applies to natural gas and/or to gas utilities which operate "services of general economic interest" indicate that the robust opposition of the most powerful gas (production)/transmission companies to such developments may be turned into a long-life legal battle over "freeing up" the European gas market.

ii. Perestroika in the Soviet Union. The USSR is the single most important external gas supplier to W. Europe, in spite of restrictions for political reasons by NATO. As indicated above, however, Soviet gas has not hitherto been sold aggressively. Soyusgasexport preferred, indeed, to be a member of the 'Club' and has particularly close relations with Ruhrgas. The 1986 oil price collapse severely reduced the Soviet Union's hard currency earnings and this is particularly serious in the context of Perestroika as it hinders restructuring and makes it harder to meet the rising expectations of the Soviet people. Only much expanded natural gas exports to Western Europe offer the Soviet Union an alternative to the massive borrowing that will otherwise be required to pay for necessary imports. There is no gas reserves/reserves development problem in the USSR to inhibit such exports, though Western investment and technology may be required to speed up the process - but this could be paid for by some of the extra gas sold to Europe. Thus the Soviet Union must be seriously considering the prospects for making large additional gas sales to W. Europe though clearly with misgivings for the possible impact on market stability. If it were to chose to take such action, then the effect would be to open up the gas sector of the W. European energy economy to effective competition - and, of course, would bring downward pressure on gas prices.

4. Concluding Remarks

a. The limited exploitation of Western Europe's own gas reserves and the limitations on gas' penetration of lower-value markets has inhibited, and continues to inhibit, the role of gas in the region's energy economy. The existing gas industry structure wishes - and envisages - the continuation of the status quo so that gas' share of total energy supply will remain at about 18% while gas prices will remain relatively high, especially for industry and power generation.

b. Alternatively, there are forces with a potential to create a more competitive gas market, whereby indigenous production is much increased, much additional gas is imported and gas' share in the total supply of energy rises to 27% by 2000 : and the average gas price declines markedly.

c. The 'battle-lines' for the 1990s over gas in W. Europe are now being drawn : with the gas industry monopolies, often supported by governments, on the one side ; and with potential large gas users, linked with environmental forces, on the other side. The EEC now favours the latter and may thus push for change with the threat of legal action (at the level of the European Court) if it is opposed by the industry. If the Soviet Union chooses or is forced through economic circumstances to offer large additional volumes of gas for export as well, then by the end of the century natural gas will not only have replaced oil as the single most important source of energy, but also have inhibited the expansion of coal markets and have taken away some of the anticipated growth in the demand for electricity. The chances of such a development I currently assess to be less than 50 : 50, but they are steadily increasing in response to the emerging dynamics of the energy market in Western Europe and its accompanying environmental implications.

Rotterdam, August 1989

5. An Appendix of Tables and Illustrations

1. Map: The W. European Gas Supply and Transmission System

2. Table: The Evolution of W. Europe's Gas Reserves 1956-96

3. Table: N.W. Europe ; Hydro Carbons Production to 1987 and Recoverable Reserves Remaining

4. Map: A Comparison of the Geography of Gas Production and Use in W. Europe, the U.S. and the U.S.S.R.

5. Map: Off-Shore Western Europe : Areas of Hydro Carbons Production and Potential

6. Table: Natural Gas Use in Western Europe, 1961-86

7. Table: Share of Natural Gas in Total Energy Use in W. European Countries, 1977 and 1987

8. Table: W. European Countries : Exports/Imports of Gas, 1977 and 1987

9. Table: Alternative Potential W. European Energy Supply Patterns in 2000

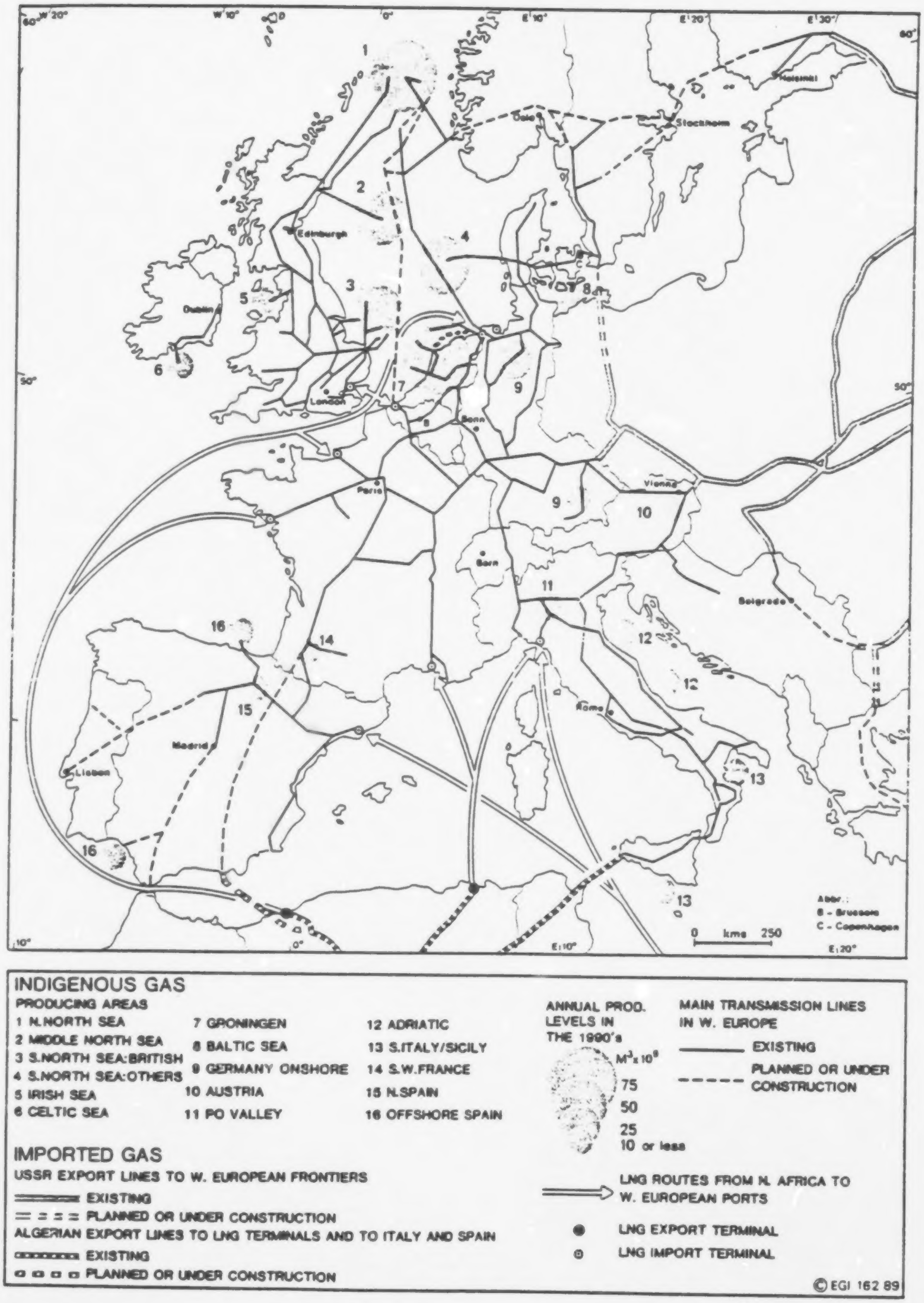

INDIGENOUS GAS
PRODUCING AREAS
1 N.NORTH SEA
2 MIDDLE NORTH SEA
3 S.NORTH SEA:BRITISH
4 S.NORTH SEA:OTHERS
5 IRISH SEA
6 CELTIC SEA
7 GRONINGEN
8 BALTIC SEA
9 GERMANY ONSHORE
10 AUSTRIA
11 PO VALLEY
12 ADRIATIC
13 S.ITALY/SICILY
14 S.W.FRANCE
15 N.SPAIN
16 OFFSHORE SPAIN
ANNUAL PROD. LEVELS IN THE 1990's
M³x10⁹
75
50
25
10 or less
MAIN TRANSMISSION LINES IN W. EUROPE
EXISTING
PLANNED OR UNDER CONSTRUCTION
IMPORTED GAS
USSR EXPORT LINES TO W. EUROPEAN FRONTIERS
EXISTING
PLANNED OR UNDER CONSTRUCTION
ALGERIAN EXPORT LINES TO LNG TERMINALS AND TO ITALY AND SPAIN
EXISTING
PLANNED OR UNDER CONSTRUCTION
LNG ROUTES FROM N. AFRICA TO W. EUROPEAN PORTS
LNG EXPORT TERMINAL
LNG IMPORT TERMINAL
© EGI 162 89
Abbr.:
B - Brussels
C - Copenhagen
0 kms 250
Edinburgh
Dublin
London
Paris
Bonn
Bern
Vienna
Belgrade
Rome
Madrid
Lisbon
Oslo
Stockholm
Helsinki
60°
50°
W 20°
W 10°
0°
E 10°
E 20°
E 30°

Figure Western Europe's Gas Production Potential in the 1990s and the Transmission System for both Indigenous Gas and for Imports

Evolution of W.Europe's Natural Gas Reserves

1956-1986 (+ a forecast for 1996)

($m^3 \times 10^9$)

Year	Cumulative Production to date	Cum.Prod. over previous decade	Year.End.Decl. Proven/Prob. Reserves	R/P Ratio (Years)	Total Orig. Recoverable Reserves	Net Reserves Additions in Decade
1956	50	35	c.500	c.40	550	n.k.
1966	225	175	c.1900	c.76	2125	1575
1976	1150	925	c.4350	c.27	5500	3375
1986	2900	1750	c.7900	c.44	10800	5300
Forecast 1996	c.5150	c.2250[x]	c.11250[*]	c.45	c.17150	c.5600

x Assuming the Continuation of Present Policies

* On the basis of fields already discovered only. There is, of course, a near zero probability that no more fields will be found, given the continuation of an extensive exploration effort in many W.European countries.

Table

North-West Europe : Hydrocarbons Production to 1987 : and Recoverable Reserves Remaining (and the total declared in developed/developable fields by 2000)

(in milliards - 10^9 - of barrels of oil equivalent)

Country	Cumulative Production to end 87			Reserves Remaining									Recoverable Reserves Declared to end-1987		
				In Existing Fields			In Fields to be Developed			Total					
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
Norway	2.2	1.53	3.37	7.5	2.65	10.15	6.75	12.1	18.85	14.25	14.75	29.0	16.45	16.28	32.73
U.K.	7.85	3.82	11.67	6.37	3.97	10.34	3.68	3.09	6.77	10.05	7.06	17.11	17.9	10.88	28.78
Neths.	0.53	8.7	9.23	0.55	11.5	12.05	0.25	0.45	0.7	0.8	11.95	12.75	1.33	20.65	21.98
W.Germany	0.45	1.9	2.35	0.73	1.55	2.28	0.2	0.74	0.94	0.93	2.29	3.22	1.38	4.19	5.57
Denmark	0.13	0.01	0.14	0.4	0.38	0.45	0.83	0.78	0.83	0.78	0.83	1.61	0.91	0.84	1.75
Ireland	0.0	0.07	0.07	0.0	0.3	0.3	0.2	0.18	0.38	0.2	0.48	0.68	0.2	0.55	0.75
Totals	11.18	16.03	27.19	15.55	20.35	35.9	11.46	17.01	28.47	27.01	37.36	64.37	38.17	53.39	91.56

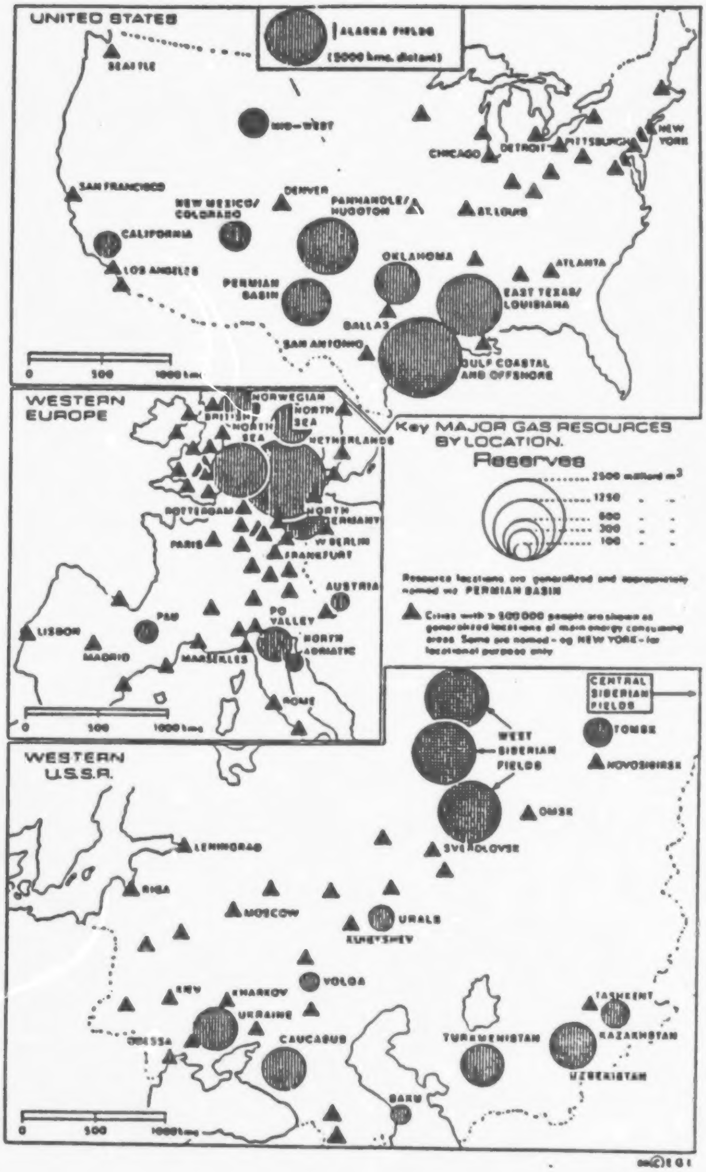
Notes on Sources

i. Cumulative production from national/EEC/IEA statistics on annual production.

ii. Remaining Reserves in existing fields from national data on oil and gas reserves updated to end-1987 from the technical press.

iii. Reserves in fields to be developed : from the Survey of development projects and prospects 1988-99 based on operators' replies to questionnaires, *Offshore Engineer*, January 1988 pp.26-44.

iv. Recoverable Reserves declared to end-1987 - sum of cumulative production plus total reserves remaining at end '87. This is not an indication of ultimately recoverable reserves or even of reserves in all discovered fields : many of the latter do not yet have development prospects or are not even fully appraised.


UNITED STATES
ALASKA FIELDS
(5000 kms. distant)
SEATTLE
MID-WEST
SAN FRANCISCO
NEW MEXICO/ COLORADO
DENVER
PANHANDLE/ HUGOTON
CHICAGO
DETROIT
PITTSBURGH
NEW YORK
ST. LOUIS
CALIFORNIA
LOS ANGELES
OKLAHOMA
ATLANTA
PERMIAN BASIN
EAST TEXAS/ LOUISIANA
DALLAS
SAN ANTONIO
GULF COASTAL AND OFFSHORE
0
500
1000 kms
WESTERN EUROPE
BRITISH NORTH SEA
NORWEGIAN NORTH SEA
NETHERLANDS
ROTTERDAM
NORTH GERMANY
W. BERLIN
PARIS
FRANKFURT
AUSTRIA
LISBON
MADRID
PO VALLEY
MARSEILLES
NORTH ADRIATIC
ROME
0
500
1000 kms
Key MAJOR GAS RESOURCES BY LOCATION.
Reserves
2500 milliard m³
1250
500
300
100
Resource locations are generalized and appropriately named viz PERMIAN BASIN
Cities with > 500 000 people are shown as generalized locations of main energy consuming areas. Some are named – eg NEW YORK – for locational purposes only
WESTERN U.S.S.R.
CENTRAL SIBERIAN FIELDS
WEST SIBERIAN FIELDS
TOMSK
NOVOSIBIRSK
OMSK
SVERDLOVSK
LENINGRAD
RIGA
MOSCOW
URALS
KUYBYSHEV
VOLGA
KIEV
KHARKOV
UKRAINE
ODESSA
CAUCASUS
BAKU
TURKMENISTAN
TASHKENT
KAZAKHSTAN
UZBEKISTAN
0
500
1000 kms

oo©EGI

Figure The proximity of gas production and energy using areas in Western Europe compared with the USA and the USSR.

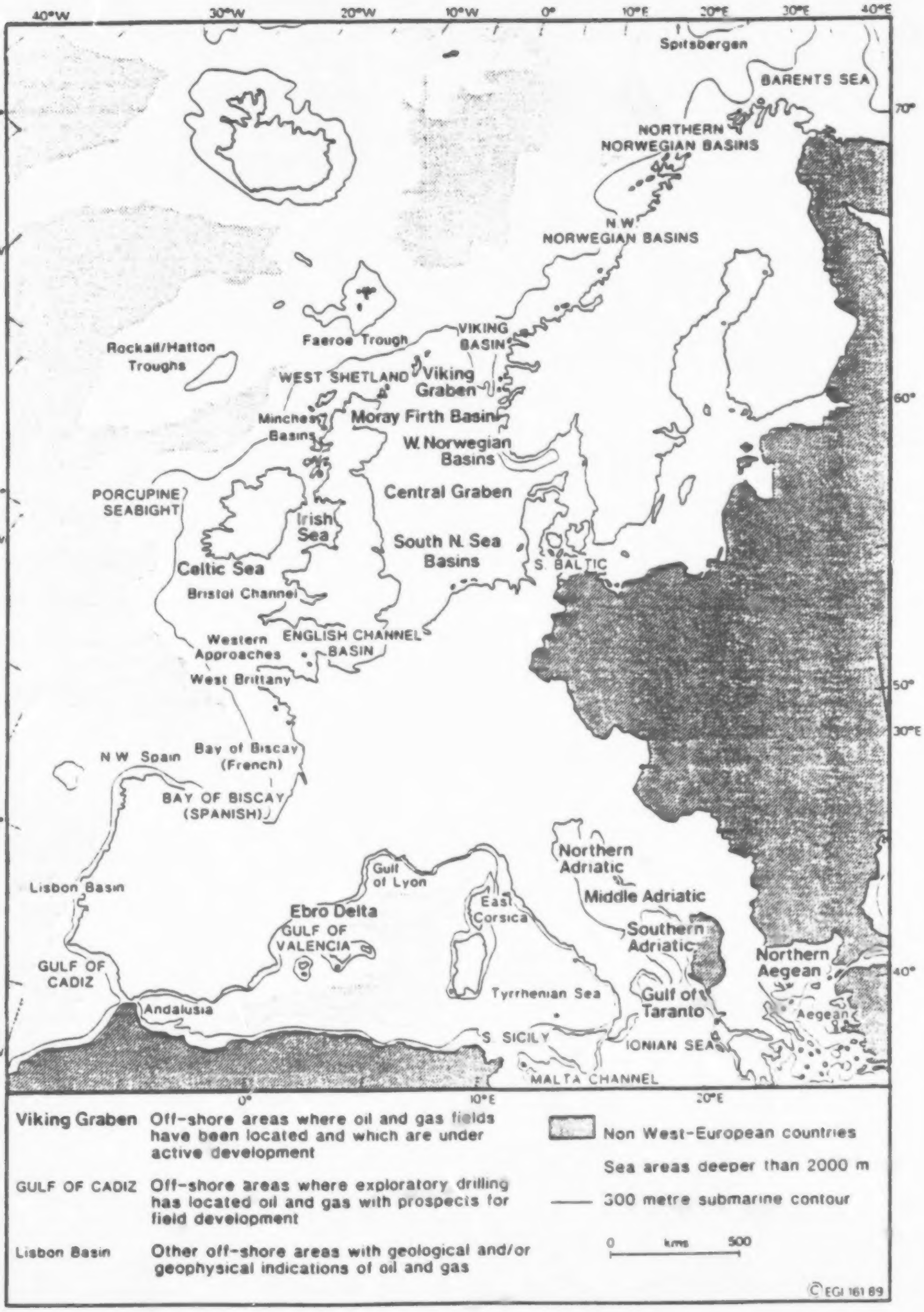

40°W
30°W
20°W
10°W
0°
10°E
20°E
30°E
40°E
60°
30°W
50°
20°W
40°
10°W
70°
60°
50°
30°E
40°
0°
10°E
20°E
Spitsbergen
BARENTS SEA
NORTHERN NORWEGIAN BASINS
N.W. NORWEGIAN BASINS
Rockall/Hatton Troughs
Faeroe Trough
VIKING BASIN
WEST SHETLAND
Viking Graben
Minches Basins
Moray Firth Basin
W. Norwegian Basins
PORCUPINE SEABIGHT
Central Graben
Irish Sea
South N. Sea Basins
Celtic Sea
S. BALTIC
Bristol Channel
Western Approaches
ENGLISH CHANNEL BASIN
West Brittany
N.W. Spain
Bay of Biscay (French)
BAY OF BISCAY (SPANISH)
Lisbon Basin
Gulf of Lyon
Northern Adriatic
Middle Adriatic
Ebro Delta
East Corsica
GULF OF VALENCIA
Southern Adriatic
Northern Aegean
GULF OF CADIZ
Tyrrhenian Sea
Gulf of Taranto
Andalusia
Aegean
S. SICILY
IONIAN SEA
MALTA CHANNEL
Viking Graben
Off-shore areas where oil and gas fields have been located and which are under active development
GULF OF CADIZ
Off-shore areas where exploratory drilling has located oil and gas with prospects for field development
Lisbon Basin
Other off-shore areas with geological and/or geophysical indications of oil and gas
Non West-European countries
Sea areas deeper than 2000 m
300 metre submarine contour
0 kms 500
© EGI 161 89

Figure Western Europe's Petroliferous and Potentially Petroliferous Offshore Areas

Table 1

NATURAL GAS USE IN WESTERN EUROPE 1961-1986 (in $m^3 \times 10^9$)

Country	1961	1966	1971	1976	1981	1986
Austria	1.2	1.9	3.3	4.5	4.3	5.0
Belgium/ Luxemburg	-	0.1	6.4	11.3	10.5	8.4
Denmark	-	-	-	-	-	1.2
Finland	-	-	-	0.9	0.7	1.1
France	4.4	5.9	12.2	20.9	27.0	25.7
Greece	-	-	-	-	-	0.1
Iceland	-	-	-	-	-	-
Ireland	-	-	-	-	1.0	1.5
Italy	6.5	9.0	13.8	24.2	25.1	31.0
Netherland	2.3	3.3	27.1	36.3	33.0	35.5
Norway	-	-	-	-	-	-
Portugal	-	-	-	-	-	-
Spain	-	-	0.5	1.6	2.3	2.6
Sweden	-	-	-	-	-	0.2
Switzerland	-	-	-	0.6	0.9	1.0
Turkey	-	-	-	-	-	0.3
United Kingdom	-	0.9	19.9	38.1	44.7	54.0
West Germany	1.6	4.0	22.8	39.9	45.5	44.2
Totals ($m^3 x 10^9$)	16.0	25.4	105.8	178.3	196.9	211.8
Number of Countries (out of 18) using Natural Gas	5	7	8	10	11	15
Natural Gas as a Percentage of Total Western Europe Energy Use	1.8%	3.3%	9.7%	13.4%	14.7%	15.2%

Source: Derived from B.P.'s 1987 Annual Review of World Energy and earlier years' issues of B.P.'s Statistical Review of the World Oil Industry.

TABLE
GAS IN TOTAL PRIMARY ENERGY CONSUMPTION IN WEST EUROPEAN COUNTRIES 1977 AND 1987

	1977	percent	1987
Largest Gas Consumers			
Netherlands	43.6		45.8
United Kingdom	17.4		24.3
Italy	16.3		21.8
Belgium/Luxembourg	19.2		16.9
West Germany	14.8		16.7
France	11.0		12.6
Other Countries			
Austria	17.5		17.1
Irish Republic	-		14.8
Denmark	-		7.1
Finland	3.6		5.8
Spain	2.0		3.5
Switzerland	2.4		3.2
Total W. Europe	13.7		15.9

Note: Hydro and nuclear electricity are converted to primary energy on the basis of the amount of fossil fuel required to generate a similar amount of electricity; if the conversion were made on the basis of heat output, the share of natural gas in primary energy consumption would rise, for Western Europe in total, from 13.7% to 14.9% in 1977 and from 15.9% to 18.2% in 1987.

TABLE
NET IMPORTS OR EXPORTS OF GAS FROM/TO WESTERN EUROPEAN COUNTRIES, 1977 AND 1987

	1977	1987	Change
	millions of cubic feet per day		
Net Importers			
West Germany	2,621	3,071	+ 450
France	1,423	2,322	+ 899
Italy	1,070	1,872	+ 802
United Kingdom	182	1,188	+ 1006
Belgium/Luxembourg	1,081	910	- 171
Others	503	771	+ 268
Net Exporters			
Norway	278	2,825	+ 2547
Netherlands	4,269	2,408	- 1861
Denmark	-	75	+ 75
Total Net Imports	2,333	4,826	+ 2,493

Note: Net imports/exports are derived from consumption plus or minus production and thus do not take account of stock changes, etc.

Table

Alternative Potential Western European Energy Supply Patterns in 2000 under
A. Continued Constraints on Natural Gas Markets
B. the Development of a Competitive Gas Market
(quantities in millions of tons of oil equivalent)

Energy Sources	Estimated 1988 Energy Supply Pattern			Alternative Patterns in 2000 A			Alternative Patterns in 2000 B		
	Total	Indigenous	Imports	Total	Indig.	Imp.	Total	Indig.	Imp.
Natural Gas	215	170	45	230	140	90	335	205	130
%	18.9			18.7			26.7		
Oil	605	200	405	575	125	450	580	200	380
%	53.3			46.7			46.2		
Coal etc.	215	155	60	285	150	135	220	120	100
%	18.9			23.2			17.5		
Primary Elect.[1]	100	100	-	140	140	-	120	120	
%	8.8			11.4			9.6		
Total Energy Supply	1135	625	510	1230	555	675	1255	645	610
%	100	55.1	44.9	100	45.1	54.9	100	53.0	47.0

---

[1] Primary electricity (including nuclear power) converted to m.t.o.e. on the basis of the heat value of the electricity produced.

OUTLOOK FOR LNG MARKETS WORLDWIDE

Presented by

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EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989.

May I first explain, to avoid any misunderstanding, that quite co-incidentally I presented a paper on this subject only last week to the LNG-9 Conference in Nice. As you might expect, I have no new message to offer less than one week later. However, as I know that the Canadian representation at LNG-9 was very small, I trust that for most of you here today, what I have to say will indeed be fresh news for you.

With that explanation, let me begin.

World LNG trade has increased every year since its birth in late 1964, except for 1980 and 1981 when it fell back temporarily due mainly to the collapse of the Sonatrach-El Paso project. Since the mid-1970s, Japan has been the world's largest market for international LNG comprising about 70 per cent or 30 million tonnes of the total business in 1988.

On the other side of the equation, Indonesia has been the largest supplier since the early 1980s with 40 per cent or 18 million tonnes of total supplies in 1988. Overall, international LNG trade has increased by an average of some 20 per cent per annum or by over 40 million tonnes between 1970 and 1988.

In the main, the LNG business has lived up to its early expectations in terms of its growth rate, contractual performance, safety record and reliability of supplies, with the exception of the United States' market which many forecasters - including myself - originally expected would have become by now at least as large as the Japanese market. The reasons for this disappointment are well documented and understood and therefore do not require restatement here today. Moreover, I do not wish to spend too much of my limited time on past history except where it is relevant to the future.

Briefly then, when I look back at my various forecasts of LNG demand over the last 15 years or so, it is clear that they were mostly, especially in the earlier years, somewhat overly optimistic and perhaps attached too much regard to the aspirations of various parties than to the realities of life. One lesson I have learnt over this period is that future supply prospects cannot and should not be quantified simply by adding up projects that have been reported by the media. Equally, nor can future demand be assessed with any certainty from the projections made by governmental agencies, utilities, industry associations and the like.

The situation is far more complex than this. In reality, the future demand for LNG will be conditioned by a whole variety of factors. Some of these factors have little to do directly with the business. Some result from unpredictable decisions taken by governments, or reflect changes in public concerns and perceptions, or yet again are the unforeseeable consequences of interfuel competition, energy price relationships and so on. Moreover, these and other factors do not necessarily have the same degree of impact in the Pacific Basin as in European markets, while the United States will yet again be different assuming that it will become a significant market for LNG in the coming years.

Let me start with the Pacific Basin, in particular Japan. On balance, current perceptions suggest that LNG demand is likely to grow more strongly in the coming years than was thought to be the case only two or three years ago. Some of the reasons for this change in perception are:

- Strong economic growth in general, and for electricity demand in particular.
- Increasing concerns on environmental issues have surfaced in the shape of growing public resistance to a planned substantial increase in nuclear power generating capacity. Gas is well placed to take advantage of this situation.
- The efforts of gas utilities to increase the use of gas for industrial purposes.

In addition, there is the ever present desire to reduce dependence on imported oil by diversifying total energy supply by source and type complemented by various other positive influences which favour growth in gas demand. Likewise, there are some constraints, including the problems in finding sites for new terminals, the difficulty for gas to penetrate the residential space heating market, and the relative inflexibility of LNG supplies compared with oil and coal, although LNG supply has become somewhat more flexible in recent years.

My current estimate of the demand for LNG in Japan over the next 20 years ranges from 46 to 53 million tonnes by the year 2010 from a current level of 30 million tonnes. The High Case assumes that the factors favouring LNG will predominate, while the Low Case assumes LNG will have a harder fight to retain its share of a more moderate expansion of energy demand against fierce competition from low-priced alternative fuels. My feeling today is that the industry is more likely to realise something nearer to the High Case than the Low Case.

As to supply, it should be noted that most existing contracts are due to expire within the next 10 years or so. On the face of it, a huge gap will open up in the 1990s between contracted supplies and forecast demand. However, in reality, this gap is likely to be very much smaller as Abu Dhabi, Indonesia and Malaysia are expected not only to extend but also to expand their supplies, while Brunei is seeking to extend its contract by 20 years. No doubt Australia will also be looking to increase its supplies once the N.W. Shelf project is well underway.

Competition between these established suppliers to acquire their fair share of new business will undoubtedly be fierce, and prospective suppliers will have a tough time to get new projects off the ground, particularly if they need large volumes and a quick build up to be economically viable. Nevertheless, there will probably be one or two new grass-roots projects coming forward for start up in the late 1990s, or in the early part of the next century, but not nearly as many as some forecasters have suggested.

Other obvious markets in the Pacific Basin are South Korea, which started importing LNG in 1986, and Taiwan, which is due to take first deliveries in 1990. At least for the remainder of this century, likely demand in these two markets could be met from established supply sources, but either or both countries may, of course, decide to take part of the future supplies from new sources if these are offered on a competitive and acceptable basis.

Turning now to Europe, adequate supplies of natural gas are under contract to meet expected demand in most countries through to the late 1990s, although existing contractual flexibility offers some scope for new supplies to be introduced somewhat earlier. Moreover, there are a few countries in Scandinavia and Southern Europe where the need for additional gas supplies could arise in the early to mid 1990s, particularly if gas is permitted by the EEC to play a bigger role in power generation.

A perennial concern of utilities, and for that matter of governments as well, is to avoid undue reliance on any particular source or sources of supply. In 1988, Continental Europe, that is excluding the UK, dependence on imported gas from non-OECD sources, essentially from Algeria and the Soviet Union, was 35 per cent and this could jump to over 50 per cent in the early part of the next century. If Dutch and Norwegian gas are included, then total cross-border trade in gas is likely to rise from 60 per cent in 1988 to some 75 per cent by the year 2010 most of which will originate from these four countries.

The implications of this are self-apparent. And even if the IEA's present guidelines which state that no country should depend as to more 30 per cent of its total gas supplies from any one non-OECD source are relaxed, will the countries and utilities concerned wish to rely increasingly on such a few sources? If we then couple this with the upward pull on demand then here is an opportunity for LNG from new and different sources to expand and diversify Europe's gas supply portfolio. It is because of these sorts of reasons that utilities have shown serious interest in Nigerian LNG, despite the relatively comfortable supply position that will exist over the medium term.

These and other factors collectively suggest that over the next 20 years LNG deliveries into Europe could at least double, or under more optimistic assumptions quadruple in volumetric terms, giving a range of 25 to 40 million tonnes by 2010 compared with about 11 million tonnes in 1988. I would go further and say that the constraint in growth for LNG may be more a question of the timely provision of new LNG supplies at acceptable prices than of any longer term limitations on overall gas demand.

Apart from the timely provision of new LNG supplies, I have one other main uncertainty as far as Europe is concerned which applies to both pipeline gas and LNG. This centres around the possible effects of certain legislation that may be introduced by the EEC. My concern is that if the existing market structure is severely disrupted by the enforced introduction of common carriage with its likely knock-on effects, prospective suppliers may find it difficult to get utilities to under-write the huge investments required for new gas projects. By under-writing I mean, of course, committing themselves to long term offtake contracts without which suppliers may not be able to secure the necessary finance on acceptable terms. If only legislators would let the industry get on with the business without interference, everyone would ultimately benefit as they have done so in the past.

Despite these reservations, I still feel that the need and prospects for LNG in Europe are bright, and if the industry does not achieve a trade somewhere close to the High Case, I will be surprised and disappointed.

Lastly, we come to the United States. Apart from some seasonal fluctuations, gas consumption declined by some 3.5 Tcf or over 90 billion cubic metres between 1979 and 1986, although it has increased by a total of 11 per cent during the past two years. While there is still an overhang of supply capacity - the so-called gas bubble - this is expected to virtually disappear in the next couple of years.

As to the future, there is no consensus on likely demand nor on supply availability. Some commentators predict that demand will continue to rise through to the next century, while others expect a rather flat situation or even a decline in demand.

Who is right remains to be seen, but part of the answer must surely be a function of how much gas can be discovered and produced within the United States at prices which are competitive with alternative fuels.

With a current proven reserves to a production ratio of about 11 to 1, the United States has got to find and develop a lot of low cost gas rather quickly to meet current levels of demand in the 1990s, let alone any future increases in demand of any consequence. And with development well drilling activity currently only some 35 per cent of the 1981 level, a high and rapid increase in exploration and development drilling is obviously needed. Canadian gas imports can help somewhat, but it is unlikely that these could increase by much more than 1 Tcf above current levels, and any Mexican gas imports would most probably be very small in relation to the total US market.

My own view is that through the 1990s the US gas market will become increasingly supply constrained, the more so if oil prices remain low. By low I mean crude oil prices which on average remain somewhat below 20 dollars a barrel.

In the situation I have described, LNG imports can be a useful, indeed an essential supplement to indigenous gas and Canadian pipeline gas imports, provided, of course, they can be delivered at the right locations at marketable prices which I believe can be done. Apart from this proviso, the main limitation on LNG imports, at least for some years to come, is probably the existing terminal capacity given the considerable difficulties that exist in the

US in getting approvals for new facilities of this nature. On these assumptions imports of LNG could range from about 6 to 17 million tonnes by 2010 compared with less than 1 million tonnes in 1988.

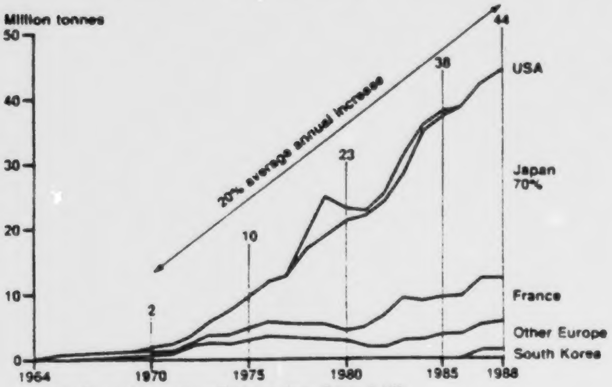
Before leaving North America, it is also possible that you here in Canada may also wish to import limited quantities of LNG in the coming years to assist in balancing your loads at times of peak demand in eastern markets.

My time has virtually run out, although there are many other matters I should liked to have mentioned if time had permitted. But just one point I should like to stress is that technical innovation and the minimisation of costs, particularly of liquefaction plants and ships, but without reducing safety standards, will be absolutely crucial to the realisation of new business.

In 1988, total international LNG trade amounted to some 43 million tonnes and my forecast is that it could expand to between 88 and 130 million tonnes by the year 2010. Admittedly, this is a fairly wide range but then there are many imponderables before us and forecasting is fraught with hazards. Even so, if the industry does not realise a business equivalent to at least 100 million tonnes by the first decade of the next century then we ought to be ashamed of ourselves - the opportunity is there.

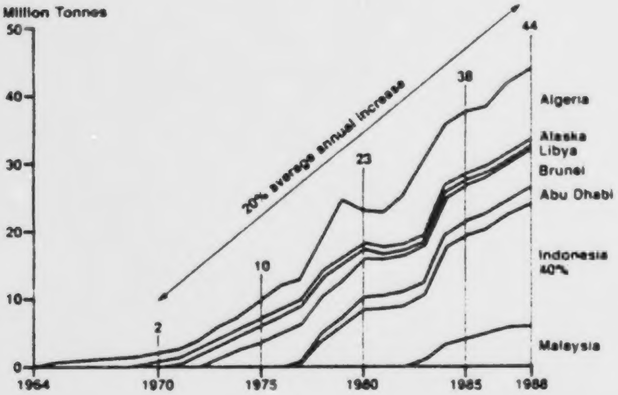
Finally let me put the LNG business into perspective. It is very important for some countries but it is still likely to be a relatively modest 5 per cent of total world gas consumption by the year 2000. Modest it may be in this context, but it will still require a huge effort and dedication from all of us if we are to realise a business of this dimension over what is in fact a relatively short time frame. It can be done, let us do it.

WORLD LNG TRADE BY MARKET

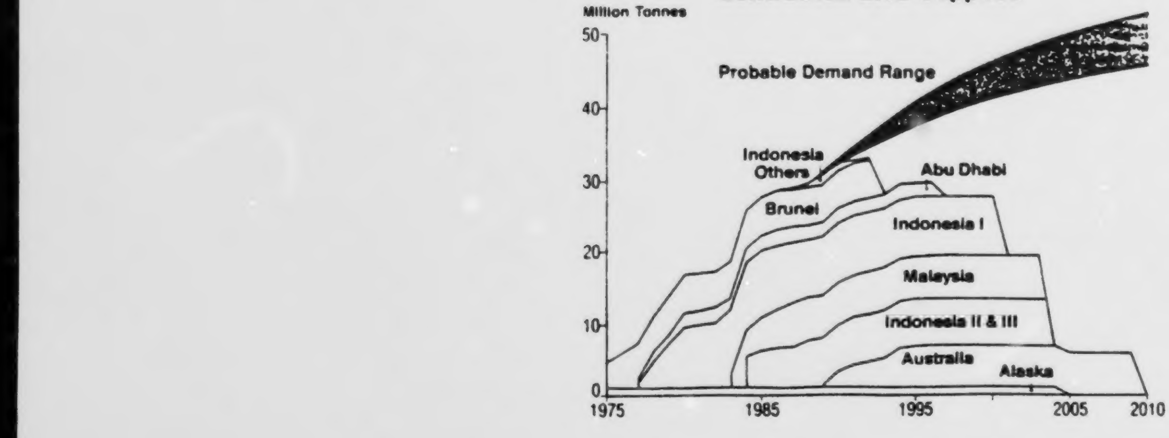


'Other Europe' comprises Belgium, Italy, Spain & UK

WORLD LNG TRADE BY SOURCE

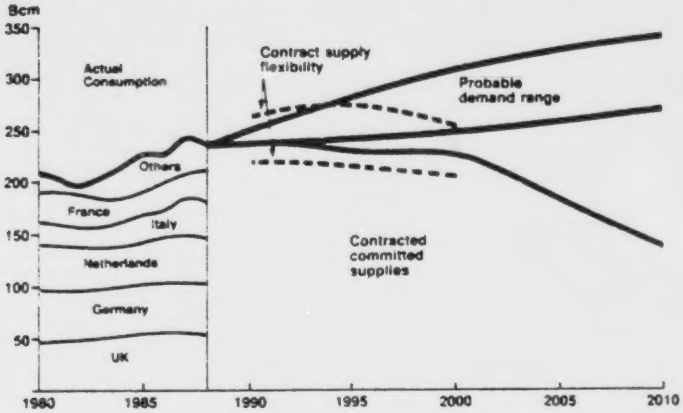


Japan
Contracted LNG Supplies



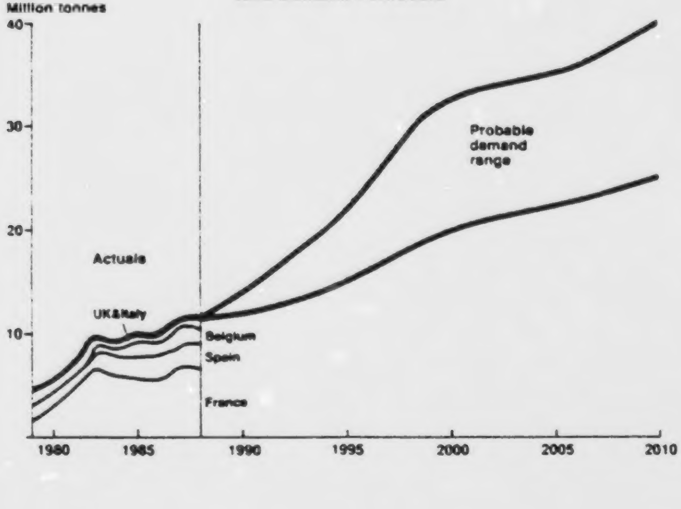
WEST EUROPE

Natural Gas Supply & Demand

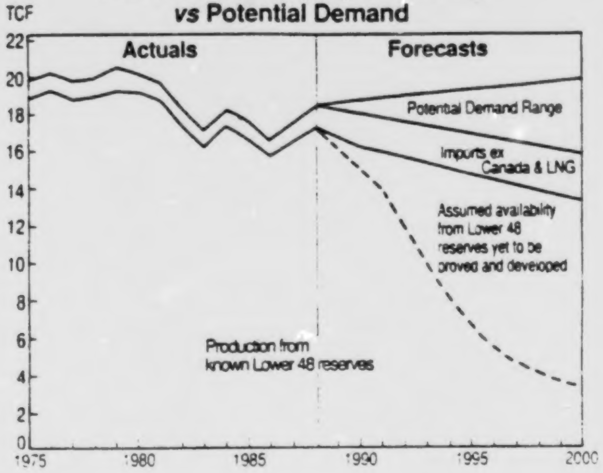


WEST EUROPE

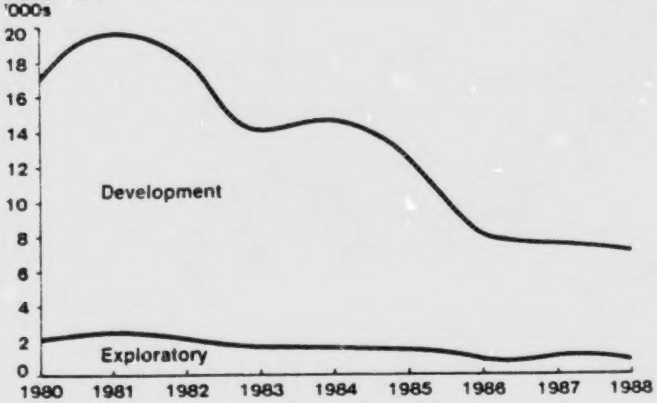
LNG Demand Forecasts



USA Assessed Supply Availability *vs* Potential Demand



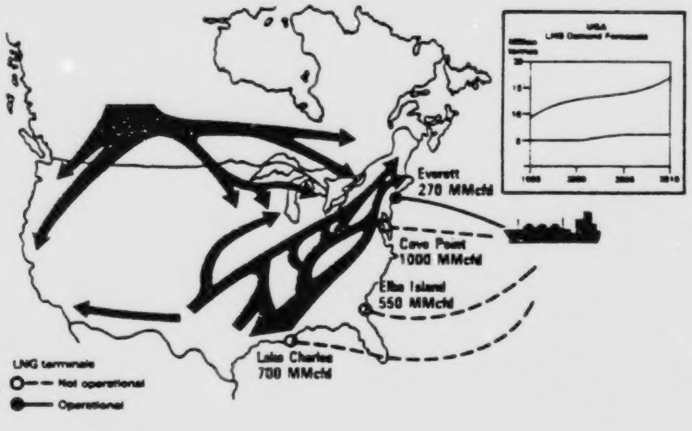
USA
Gas Well Completions



Source: American Petroleum Institute

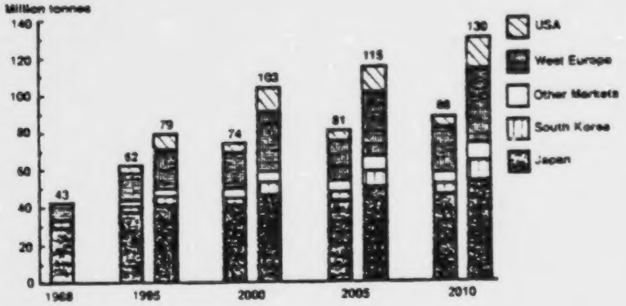
NORTH AMERICA

Principal movements of pipeline gas and LNG (prospective)


Everett
270 MMcfd
Cove Point
1000 MMcfd
Elba Island
550 MMcfd
Lake Charles
700 MMcfd
LNG terminals
Not operational
Operational
USA
LNG Demand Forecasts

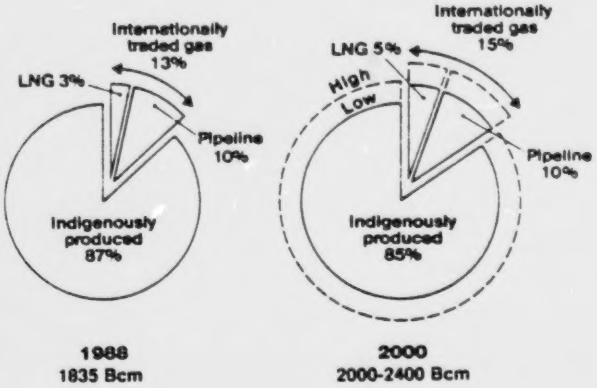
WORLD LNG DEMAND

Low and High Case Forecasts



World Natural Gas Consumption

Forecast Growth in International Traded Gas



LNG SUPPLY AND DEMAND IN JAPAN

Presented by

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At
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OIL AND GAS MARKETS CONFERENCE
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1. Introduction

LNG was introduced into Japan in 1969, a few years before the first oil crisis, when Tokyo Electric Power Co., Inc. and Tokyo Gas Co., Ltd. jointly imported the first cargo of Alaskan LNG. In subsequent years, the two oil crises dictated a complete overhaul of Japan's energy policy. Due to its special characteristics of supply stability and cleanness, LNG has come to receive high evaluation as the main pillar of Japan's alternative energy sources. With electric power and utility gas industries as the major consumers, Japan's LNG imports have grown rapidly.

Overseas projects now supplying LNG to Japan include those in Alaska, Brunei, Abu Dhabi, Indonesia (#1, #2 and #3), Malaysia and Australia -- eight in all. Imports of LNG from Australia, the latest supply source, began in September 1989. LNG imports in 1988 totaled 31 million tons, accounting for around 10% of Japan's total primary energy supply. Of these total imports, a predominantly high ratio of 80% is being consumed for power generation, the remainder (20%) being used for production of utility gas.

The rate of growth of Japan's electric power demand slowed as we entered the 1980s. In addition, nuclear power and coal-fired power generation, because of their economic advantage, came to provide the base load. Under such circumstances, LNG consumption for power generation is projected to level off in and after 1995. As for LNG demand for utility gas, three major firms have nearly completed a shift of feedstock to LNG. Consumption of city gas in the residential sector -- the largest of all gas-consuming sectors -- is reaching the saturation point as the use of gas appliances has been fully disseminated by now in that sector. Growth in city gas demand in the future is thus expected to be seen in commercial and industrial sectors.

Against the background outlined above, MITI worked out a long-term energy supply and demand forecast for Japan in 1987. According to the latest revised MITI forecast, LNG demand growth is forecast to slow rapidly -- rising from 30 million tons in 1987 to 36 million tons in 1995, but only to 38 million tons in 2000.

The collapse of crude oil prices in 1986 and the settling of crude oil prices at relatively low levels in subsequent years, however, have caused energy demand to soar on the one hand, and yet, on the other hand, the anti-nuclear movement and warnings against the global environment problems have also grown apace. These developments are having a far-reaching impact on Japan's energy supply and demand structure, with LNG assuming a vital role once again.

2. LNG Demand Forecast

Energy demand in Japan remained sluggish for many years after the first oil crisis. During the 13-year period from 1973 through 1986, Japan's GNP grew at an average annual rate of 4%, while primary energy demand showed an annual increase of only 1% on the average. However, with the sharp drop in domestic energy prices due to the plunge in crude oil prices in 1986 and the yen's rapid appreciation against the U.S. dollar, coupled with the expansion of the Japanese economy centered on domestic demand, primary energy demand has shown an annual rate of increase of more than 5% -- exceeding that of GNP in recent years. Electric power demand as well has grown by around 5%

per year in and after 1986, compared with its annual growth rate of 3% in previous years.

On the supply side, the Chernobyl nuclear power plant accident triggered nationwide anti-nuclear sentiment in Japan, making it increasingly difficult for electric utilities to construct new nuclear power plants. The current long-term energy program by MITI calls for expansion of nuclear power plant capacity from 28 GW in 1988 to 54 GW by 2000. Recent indications, however, are that 46 GW will be the maximum achievable target, taking into account projects now under construction as well as those already approved by the government.

As for coal, the government forecast envisages an increase in supply from 103 million tons in 1987 to 136 million tons in 2000, the bulk of the increment being steaming coal for electric power generation. Unfortunately, however, there has emerged growing concern over restrictive measures to be taken to control the expanded utilization of coal amid the worldwide movement to address environmental problems such as acid rain and global warming in recent years.

While energy demand is expected to grow at a faster pace than previously anticipated, as noted above, expansion of nuclear power generation and coal utilization -- two major alternative energy sources -- is posing new problems. The government forecast of long-term energy published in 1987 has thus become somewhat outdated. In view of these recent developments in the energy situation, our Institute published last year-end a new long-term energy supply and demand forecast.

According to this updated forecast, Japan's primary energy demand is projected to rise from 7.7 million b/d (in oil equivalent) in 1987 to 10.1 million b/d by 2000, an 8.6% upward revision of the 9.3 million b/d projected in the government forecast referred to above. In our forecast, nuclear power and coal supplies are revised downward, while both oil and LNG supplies are projected to grow sharply by 2000 -- a 23.8% upward revision for oil from 4.2 million b/d (government forecast) to 5.2 million b/d and a 26.3% upward revision for LNG from 38 million tons (government forecast) to 48 million tons, all in 2000. LNG demand is thus forecast to grow to 39 million tons by 1995 and to 48 million tons by 2000 under the new situation. How should Japan plan to increase its LNG supply to meet the ever-growing demand?

3. Outlook for LNG Supply

On the basis of existing and planned extension of existing contracts under which LNG is being supplied to Japan, including the Australian project which came on-stream recently, contracted LNG supply now totals 34 million tons a year. Considering the fact that the actual production capacity of an LNG plant is in excess of the contract volume by around 10%, combined spare capacities of all existing LNG plants are estimated to total around 4 million tons a year, which can be added to the above 34 million tons -- totaling 38 million tons a year. This will be large enough to meet forecast demand for 1995.

When looking into LNG supply potentials for 2000, the demand situation in Asian NIEs such as South Korea and Taiwan must be taken into consideration. South Korea began importing two million tons a year of Indonesian LNG in 1986 and demand for LNG for electric power generation and utility gas as well is expected to increase to six million tons by 2000. As for Taiwan, plans are now underway to begin importing 1.5 million tons a year of LNG, also from Indonesia, in 1990 for electric power generation and utility gas. Electric power demand is growing at an average annual rate of nearly 10% in Taiwan, and yet it is becoming extremely difficult to construct nuclear or coal-fired power plants for environmental reasons, thus accelerating the increase in LNG imports and tripling the volume to 4.5 million tons by 2000.

Although the Philippines has no concrete plans for importing LNG at present, there is a possibility that LNG can become an important alternative in its efforts to diversify energy supply sources along with the country's economic expansion accompanied by energy demand growth.

In summary, LNG demand in the Asia/West Pacific region is projected to reach around 58.5 million tons by 2000 vis-a-vis existing contracts totaling 37.5 million tons, which will be raised to a maximum of 41.5 million tons when spare production capacities are considered. This means that an additional supply sources of 17 million tons must be secured to bring supply into balance with demand in 2000.

Measures to secure additional LNG supply include expansion of existing projects in addition to construction of grass-root projects. The expansion of existing projects allows the utilization of existing berths and the like and is not only more economical but also more realistic. Judging by the magnitude of natural gas reserves and policies on the part of exporters involving existing LNG projects, such expansion alone is believed sufficient to secure an additional 10 million tons a year of LNG supply, leaving two or three projects to be newly developed to secure an additional 7 million tons a year.

Meanwhile, development of new projects will help diversify sources of Japan's LNG supply -- an important move to secure LNG supply in the 21st century. Among these projects are those in the U.S. (Prudhoe Bay, Alaska), the Soviet Union (Sakhalin), China (Hainan Island), Qatar, Thailand, Burma, Papua New Guinea and Australia (Bonaparte Gulf). While these projects vary greatly in stage of development from one to another, they have a combined supply capacity of around 30 million tons a year. As long as these promising export countries are provided with incentives for LNG exports, the potential supply capacity is expected to continue outgrowing the increase in demand for LNG.

The feasibility of each of these potential projects is briefly outlined below. A Chinese project has only a remote possibility for materialization in view of limited resources and the recent political turmoil in China. A Thai project also has only a small possibility due to the high rate of growth in energy demand for domestic consumption and the government's policy of giving priority to domestic use of Thailand's natural gas supply. Projects in Burma and Papua New Guinea are still in preliminary planning stages. Concrete plans will be formed as future developments in the energy situation dictate.

Projects in which plans for LNG exports are taking concrete shape include those of Alaska's North Slope, Sakhalin and Qatar. A joint Japan-U.S. feasibility study, undertaken in 1987 for the Alaskan project, concluded that the project will be on such a large scale, requiring huge capital expenditures, that it is hardly justifiable in economic terms, especially at a time when crude oil prices remain relatively low as at present. To materialize the Alaskan project, therefore, it will be essential to reduce the capital cost to the minimum on the one hand, and to improve the resilience in LNG supply and pricing conditions on the other.

The biggest stumbling block in promoting the Sakhalin project is the Northern Territories issue -- a thorny, politically controversial issue pending for decades between Japan and the Soviet Union. Should the Gorbachev administration adopt a flexible attitude toward that issue in the future, the Sakhalin project has great possibilities for materialization.

As for the Qatari project, it has a number of factors favorable to Japan as a buyer. On the basis of its huge gas reserves, production cost is extremely low compared with that of other gas fields. Furthermore, because of its new entry into the Japanese market, Qatar is taking quite a flexible marketing strategy in terms of supply volumes and prices. Unfortunately, however, the very fact that Qatar is located on the Persian Gulf and Qatari LNG shipments must inevitably pass through the Strait of Hormuz is a serious obstacle in the way of the Qatari LNG project. One of Japan's basic energy policies is to reduce its reliance on oil, which in effect means reducing its dependence on Middle East oil -- and implicitly on Middle East energy sources as well.

As can be seen from the above, each of these new LNG projects has its own problems and it is necessary to leap a number of hurdles before LNG supply therefrom can be realized. On the other hand, it should be noted that Japan's reliance on Indonesian LNG is exceptionally high. Indonesian LNG now accounts for around 50% of Japan's total LNG imports. In this connection, Japan is urged to promote diversification of its LNG supply sources. It is vital that LNG exporting and importing countries strengthen their long-term trustful relations to overcome various economic and political obstacles that new LNG projects harbor.

4. Conclusion

The environment surrounding Japan's LNG demand has undergone drastic changes in recent years as noted above, suggesting far more rapid growth of LNG demand than previously thought. Whether the Japanese LNG demand growth projected above becomes a reality or not depends mainly on crude oil price trends and, in particular, on electric power demand, construction costs of LNG-related plant facilities, etc. For LNG to expand its share in the highly competitive Japanese energy market, what is most important is that both LNG exporting and importing countries make concerted efforts to place supply volumes and prices of LNG on a more flexible basis.

Table 1 Energy Supply Projections

Energy Form	Fiscal Year	1973		1987		1995				2000				Growth Rate (IEE case)	
						MITI		IEE		MITI		IEE			
		Actual	Share	Actual	Share	Forecast	Share	Forecast	Share	Forecast	Share	Forecast	Share	1987/73	2000/87
Nuclear	GW	1	0.7	28	11.2	42	13.4	41	13.7	54	15.9	46	14.5	23.6	4.2
Hydro	GW	7	5.0	35	4.8	43	4.3	40	4.8	46	4.4	42	4.5	0.9	1.7
Geothermal	GW	–	0.0	0.18	0.1	1.2	0.4	0.5	0.2	2.6	0.8	0.7	0.2	–	8.0
Coal	Mt	80	15.9	103	17.3	121	18.3	117	16.0	136	18.7	129	16.1	1.7	1.6
LNG	Mt	2	0.9	30	9.6	36	11.1	39	10.4	38	10.8	48	11.8	19.8	3.8
Indigenous Natural Gas	Bcf	88	0.7	78	0.5	127		81	0.4	148		81	0.4	–0.9	0.1
New Energy	10^3BD oe	59	1.1	94	1.2	216	2.5	114	1.2	422	4.5	158	1.6	1.8	4.0
Oil	MB/D	5.00	75.8	4.24	55.3	4.22	49.7	4.95	53.3	4.17	45.0	5.16	50.9	–1.2	1.5
Total Supply	MB/D oe	6.59	100.0	7.67	100.0	8.45	100.0	9.26	100.0	9.31	100.0	10.12	100.0	1.10	2.16
Real Economic Growth Rate														3.29	3.75
Energy/GNP Elasticity														0.28	0.58

Source: MITI (Oct. 1987), Institute of Energy Economics (Dec. 1988)

Table 2 Planned LNG Projects Targetting Japan

(Unit: Mil. tons)

Supply sources	Starting time of introduction	No. of contract years	Ordinary year's supply amount (contract basis)
Alaska (North Slope)	(after 1990)	20 years	14.5*
Australia (Bonaparte Gulf)	(after 1994)	-	2.3
Qatar	(after 1992)	-	6.0**
Soviet Union (Sakhalin)	(after 1990)	-	3.0
Thailand	(after 1990)	20 years	2.0-3.0
Burma	(after 1991)	20 years	1.5
China	(after 1994)	-	1.0-1.2

* Includes some destined for South Korea and Taiwan.
** Includes some destined for West Europe.

Table 3 Japan's LNG Supply And Demand Outlook By IEE

(Unit: Mil. tons)

		1987	1995	2000
Demand	Electricity	22.73	28.50	35.80
	City gas	6.39	9.90	12.00
	Others	0.55	0.40	0.30
	Total	29.67	38.80	48.10
Supply	Electricity	22.73	25.93	25.93
	City gas	6.39	7.47	7.47
	Others	0.55	0.60	0.60
	Total	29.67	34.00	34.00
Balance (Supply-Demand)	Electricity	0	-2.57	-9.87
	City gas	0	-2.43	-4.53
	Others	0	0.20	0.30
	Total	0	-4.80	-14.10
Supply sources	Alaska	0.96	0.96	0.96
	Brunei	5.23	5.14	5.14
	Indonesia I		7.50	7.50
	Indonesia II	15.39	3.20	3.20
	Indonesia III		3.30	3.30
	Abu Dhabi	2.26	2.06	2.06
	Malaysia	5.83	6.00	6.00
	Australia	-	5.84	5.84
	Total	29.68	34.00	34.00

THE PROSPECTS FOR DOWNSTREAM INVESTMENT IN THE EUROPEAN COMMUNITY

Presented by

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EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989.

This paper will review briefly what has happened to the downstream oil and gas industries of the European Community since 1973, take stock of the present situation, and go on to consider the prospects in the coming years particularly as regards consumption, investment and profitability.

Evolution of the Community Energy Market 1973-87

EEC-12 : Primary Energy Consumption 1973-1987

m/toe	1973	%	1987	%	1987/73	%
Oil	647	63	477	45	-170	-26
Gas	117	11	198	19	+ 81	+70
Solid Fuels	232	23	230	21	- 2	-
Nuclear & Other	33	3	157	15	+124	+375
Total	1029	100	1062	100	+ 33	+ 3

Since 1973 there has occurred a profound change in the energy matrix of the Community. By 1987 oil, which had represented 63% of total primary energy, had fallen to 45%. Consumption, mostly of fuel oil was down by no less than 170 million tonnes or 26%. Total energy used had changed little but there had been a massive substitution of oil by natural gas and nuclear power. Over this period, and particularly after 1980, natural gas greatly increased its market share and there was substantial investment in production and import facilities as well as in the distribution networks of several Member States.

Transformation of the Downstream Oil Industry 1973-87

For the oil refining and distribution sectors the years 1980-87 were a period of extensive rationalisation during which the number of refineries was reduced by one third, from 141 to 94, and similar retrenchment took place in storage points and retail outlets. In addition to the fall in consumption, refineries had to contend with a deterioration in the external balance; demand on the industry fell by no less than 220 m.t/y or 34%. Rationalisation was on a larger scale than in North America or elsewhere. It was accompanied, paradoxically, by large programmes of investments in conversion and, more recently, in upgrading plant for transportation fuels. Hence the average complexity of those refineries remaining in service has increased considerably.

EEC 12 : Distillation Capacity by Type of Refinery

	1980			1988		
TYPE OF REFINERY	N°	CAPACITY m.t/y	CAPACITY %	N°	CAPACITY m.t/y	CAPACITY %
Simple	62	249	27	16	43	7
Semi-complex	24	148	16	20	89	15
Complex	55	523	57	58	460	78
TOTAL	141	920	100	94	592	100

It is important to remember that in 1973 the Community industry consisted mostly of simple hydroskimming refineries whereas in the USA a high degree of conversion capacity was already in place, a consequence of the high consumption of gasoline and also of a regulatory régime which made it attractive to maximise production of lighter products from domestic crude oil and to import the shortfall of fuel oil. Hence, although the scale of the adjustment forced upon the industry was greater in the Community the trauma was mitigated by the upgrading of refinery output towards a rising proportion of higher value products. The total value of production thus fell by much less than the volume. Most of the investment went into visbreaking and catcrackers and very little into more extreme processes like hydrocracking and coking. The general assumption was that a substantial, albeit reduced, outlet for fuel oil would remain.

EEC-12 : Conversion Capacity

Millions of tons/year	1980	1985	1988	est 1990
Catalytic Crackers	47.6	83.1	81.2	81.3
Thermal Crackers	19.3	20.8	19.7	18.8
Visbreakers	24.9	46.1	57.2	56.3
Hydrocrackers	5.8	10.6	16.9	18.4
Hydroconversion	-	-	-	1.3
Coking	2.9	8.5	2.3	3.3
Flexicoking	-	-	1.9	1.9
Total	100.5	169.1	179.2	181.3
Catcracker equivalent	81	140	143	145
As % of CDU capacity	9	21	24	25

Profitability of the Refining Industry

In spite, however, of the improving quality of output, manufacturing margins remained, almost throughout this long period of rationalisation and investment, at unsatisfactory levels which failed to remunerate adequately the large sums of capital committed to conversion plant (see annexe).

Many explanations were offered for this state of affairs but there was no agreement on either cause or remedy. To us in the Commission it seemed that poor margins were inevitable in an industry where spare capacity existed and incremental production costs were low. Moreover operators with relatively low crude costs would understandably judge their revenue to be maximised at prices which offered scant remuneration to the refining function - or to the independent refiner for that matter.

The Current Situation of the Refining Industry

Since 1985 the refining industry has been in reasonable balance. Consumption has bottomed out and net imports of finished products are static or in decline. OPEC export capacity is falling and Community export opportunities particularly to the USA, are improving.. Profitability is satisfactory and utilisation of primary capacity for the EEC as a whole is close to 80%; that of conversion plant even higher.

There appears for the time being to be sufficient upgrading and conversion capacity to meet the rising demand for unleaded gasoline and middle distillates. Current programmes of investment in upgrading units and oxygenate plants, as well as in hydrodesulphurisation, are however mostly scheduled for completion by 1990. Consultations with the companies last year revealed a dearth of new projects for either conversion or upgrading plant, explained by an usually high degree of uncertainty about future environmental standards. If companies cannot reasonably foresee what these will be they plainly cannot justify investments to meet them. There can be little doubt, however, that substantial investments will be necessary in the years to come.

The future Energy Matrix and Prospects for Oil and Gas

EEC-12 : Primary Energy Consumption 1987-2000

m/toe	1987	1995*	2000*
Oil	477	541	528
Gas	198	232	249
Solid Fuels	230	248	276
Nuclear and Other	157	205	223
Total	1062	1126	1276
GDP Growth	2.7	2.7	2.7
Oil Price $87	17.9	17.3	20.0

*Commission estimates in "Energy to 2010" (Scenario 1)

As regards the evolution of the energy matrix over the next decade the Commission, in a new study "Energy to 2010", foresees in its "Conventional Wisdom" scenario, a significant (16%) rise in energy consumption between 1987 and 1995 in which all fuels share. In other words no further large scale substitution of oil by competing energy sources occurs. After 1995 natural gas is assumed to increase its market share slightly at the expense of oil whose consumption actually declines. The development of the gas distribution systems in Spain, Portugal and Greece, as well as the extension of the grid in more advanced markets to serve new areas, will by themselves ensure continued growth in demand whether further substitution for other fuels takes place or not.

This scenario is to be seen as a base case from which likely variations are to be assessed. Of necessity it takes account only of existing legislation for environmental protection and assumes that energy policy and the fiscal treatment of competing fuels remain unchanged. None of these assumptions is realistic, bearing in mind the intense political pressure for much stricter control of emissions into the atmosphere and the major review which is underway, in the context of the "Completion of the Internal Market", of the structure of the energy economy of the Community and of obstacles to competition and free movement among the Member States.

The major variations from the base case which must be considered and which are of the greatest importance to the oil and gas industries are a much larger increase in the share of natural gas at the expense of fuel oil and coal. This would apply not only to the domestic heating market but also to the industrial and electricity generation sectors. Severe restrictions upon gaseous emissions have already largely driven fuel oil off the market in Germany, Denmark and the Netherlands. This could happen in other Member States if legislation to control emissions from small combustion installations, now under consideration in the Community, takes the form of a low limit on the sulphur content of fuel oil. Such a move would not only displace fuel oil but, by exhausting the availability of naturally low sulphur material, would raise the price of industrial energy of all kinds to reflect at least partly the cost of desulphurisation.

Although coal would be less affected than fuel oil by limits on sulphur content, it could suffer, because its CO_2 emissions are higher than those of natural gas and oil, from future legislation to limit the "Greenhouse effect".

Natural gas emerges from the environmental debate as a pre-eminently desirable fuel whose use will be limited only by its supply availability - and reserves accessible to the Community could support much larger production than now foreseen. The only possible development which could work to some extent against this trend would be the introduction of fiscal neutrality among competing fuels, since natural gas now enjoys a fiscal advantage in most Member States. The imperatives of the Internal Market are bringing new pressure for neutrality, a principle widely supported by both oil companies and industrial consumers. Its adoption would plainly change the energy matrix through its effects upon both the supply and the demand for particular fuels.

Although one can argue about the pace and degree of change, there seems little doubt therefore that there will be, over the next ten years, a further pronounced swing away from oil, especially fuel oil, towards natural gas. The infrastructure for a large increase in the volume of natural gas used is already in place in most Member states and there should be no undue difficulty in financing interconnections, where they are still needed, and extensions to national grids.

The implications for the oil industry are more complex. The progressive loss of outlets for high sulphur fuel oil (even bunker fuels are attracting the attention of the environmentalists) will oblige the refining industry to undertake a new programme of investment in extreme conversion processes, notably coking and hydroconversion. Few such plants exist in the Community for the good reason that price differentials between products have not so far justified them. This seems certain to change as the price of high sulphur cracked residues falls away below coal parity and as the technology and economics of these processes improve. In many respects the Community will be going down the road already followed by the USA towards a maximum conversion industry.

Further structural change within the industry is not obviously required except in certain regions. The present number of refineries is probably not far from the minimum needed to supply efficiently the Community's still growing markets for transportation fuels and petrochemical feedstocks, although the removal of frontier controls in 1992 and the harmonisation of product quality will certainly lead to changes in distribution patterns and possibly to the closure of some plants in border regions. The very high capital cost of the new equipment needed may prompt greater corporate concentration within the industry and perhaps provide opportunities for downstream investment by producers.

Stricter controls on emissions from refinery sites, and the increased costs which they entail, will tend to improve the relative economics of source refining in regions where pollution is not a problem. Access to cheap gas will also be an important advantage for such refiners in the operation of hydroconversion and desulphurisation plants. But these comparative advantages are likely, for reasons of logistic advantages, to lead to the export to Commmunity refineries of high quality components and feedstocks, rather than to the replacement of Community production by imports of finished products from new source refineries.

Profitability of Refining in the 1990's

The prospect described above is one which, perhaps surprisingly, is likely to favour the continued profitability of much of the industry. The growth in demand for high quality products - unleaded and low-lead premium gasoline, high cetane automotive gasoil, low sulphur fuel - looks like being more rapid than anyone could have foreseen a year or two ago. This fact, together with uncertainty about the severity, nature and timing of future Community and national environmental legislation, explain why so little investment has so far been committed by the industry in plant needed to meet the requirements of the 1990's. Conversion and upgrading capacity is likely therefore to lag behind demand for some years. Prices of high specification products will be good and, conversely, high sulphur fuels and low octane components will realise low and even distress prices. These are conditions which favour a high reurn on investment and good margins, especially for those refiners which have their new plant in place in good time.

Profitability will also be enhanced by a new feature in refining economics which is of considerable importance. The marginal cost of manufacturing certain main products will be much higher in relation to average cost than was the case in the past. The incremental cost curves of both high octane gasoline components and of some oxygenates rise quite steeply as does that of low sulphur fuel oil. The incentive for refiners to run the "incremental barrel" of crude and sell the products at cut prices may well therefore disappear. Companies with spare octane capacity will be more likely to seize the opportunity to add a "super premium" unleaded grade to their range than to dispose of products on the spot market.

The Commission's view of the prospects of the hydrocarbon industries is therefore optimistic. There will be a large and continuing expansion in the volume of natural gas sales and prices will be underpinned by the rising cost of low sulphur competing fuels. The refining industry, having rationalised its structure and concentrated its activities at a much reduced number of more complex refineries, will profit from the added value of a growing proportion of high specification products and from the tight supply situation for them which will prevail for some years. Companies strong in both gas and oil markets will be particularly fortunate.

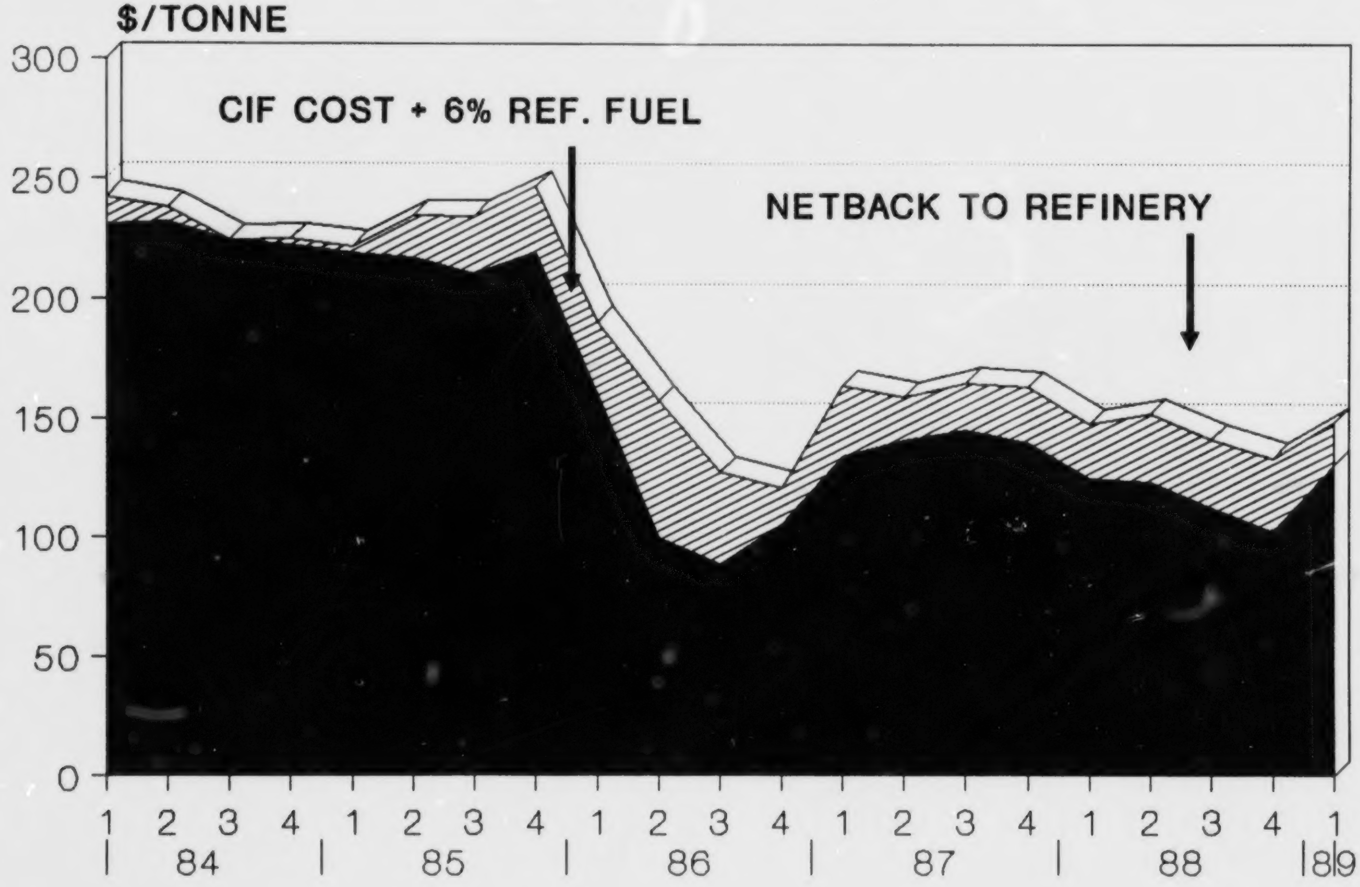
The International Dimension

All that has been said about the Community implies, of course, many assumptions about the situation in the rest of the world. The industry is globally integrated and the profitability of the European industry is as much influenced by the refining balance in North America, or the import policy of Japan, as it is by its more immediate environment. The much tighter refining balance in the States and rising product imports helps the Community's external balance both directly and indirectly. The considerable growth in oil consumption in the Pacific rim countries, and in the Gulf, supports our expectation that the world refining balance will tighten and that the surplus of products in international trade and directed at Community markets will diminish.

Similarly the point should not be lost that environmental measures taken in the Community may have profound effects elsewhere. If the EEC follows the USA and Japan in imposing much stricter standards for emissions and product quality, the marked effect on the prices of industrial energy will be general to all regions.

These are some of the reasons why it is so useful to discuss these matters at an international gathering of this kind.

EUR-12 REFINERY NETBACK VERSUS COST OF CRUDE



SOURCE: DATA FROM PRICE DIRECTIVES OF EC

DOWNSTREAM PROSPECTS FOR THE U.S. PETROLEUM INDUSTRY

PRESENTED BY

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Eighth CERI International Oil and Gas Markets Conference
Calgary, Alberta

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Ladies and gentlemen, I am honored that CERI invited me to address your Conference on the subject of petroleum refining and marketing prospects in the United States.

The petroleum industry's refining segment refuses to submit to tightly-reasoned forecasts. It squirms and jumps around when we attempt to portray it accurately in our forecasts. I have concluded that no one can consistently and accurately forecast marginal refining spreads beyond a month or so. Such forecasting is a losers' game, because merchant refining itself is a losers' game--that is, a volatile and low-return business--and likely to remain so, I think. However, the U.S. downstream industry has been steadily evolving from its merchant refining heritage; many oil firms now play other downstream "games" that offer better odds for the players than those at the merchant refining table.

(SLIDE: U.S. AND WORLD REFINING CAPACITY)

The 1980s was a decade of restructuring for the petroleum industry, a period of sobriety following the binge-like '70s. As oil demand plummeted in the early-'80s, it became clear that the refining industry--never a big earnings contributor anyway--suffered from serious and potentially chronic overcapacity. The industry responded by cutting U.S. and world refining capacity 14 percent between 1980 and 1989.

(SLIDE: PROCESSING CAPACITY OF AVERAGE U.S. REFINERY: 1980 TO 1989)

The data on refinery closures show how deeply the industry has cut to rationalize refining capacity. In the U.S., the industry shut down 118 refineries after 1980, a 38 percent drop in the number of processing facilities. Most of the closed refineries were very small--the average shut-down unit could process only 22,000 daily barrels. As a result, the processing capacity of the average refinery rose by 37 percent over ten years, from 56,600 b/d in 1980 to 77,700 b/d at present.

(SLIDE: UTILIZATION OF U.S. REFINERY OPERATING CAPACITY [PERCENT])

These shutdowns, combined with growth in U.S. oil demand after 1987 produced steadily higher capacity utilization rates throughout the 1980s.

Today, the American Petroleum Institute reports that U.S. refiners operate near 90 percent of their rated distillation capacity.

(SLIDE: SHARE OF U.S. OPERATING REFINING CAPACITY CONTROLLED BY EIGHT LARGEST U.S. REFINERS IN 1980 AND 1989)

Another sign of the rationalization of the U.S. downstream business has been the steady growth in the market share of the country's top refiners. The eight largest U.S. refiners today control 53 percent of the country's refining capacity, up from 49 percent in 1980. The growing concentration of the major firms is even more pronounced in local markets. For example, the three largest refiners in Texas--Exxon, Amoco and Chevron--today control 32 percent of the state's petroleum refining capacity, up from 21 percent in 1980.

(SLIDE: AVERAGE MONTHLY SALES OF GASOLINE IN U.S. SERVICE STATIONS: 1980 THROUGH 1988)

U.S. oil firms have also improved their marketing businesses. The steady raise in average service station sales--from about 53,000 gallons per month per station in 1980 to nearly 100,000 gallons a month last year--is the best example of this. Voluntary withdrawals from regions of low market penetration combined with strategic swaps and purchases have allowed most firms to raise market shares in core markets. For example:

- Mobil recently swapped its Pacific Northwest service stations for British Petroleum's East Coast outlets, strengthening Mobil's already substantial gasoline market share in the Middle Atlantic states;
- Sun Company's purchase of Atlantic Refining has made it the premier gasoline marketer in Pennsylvania;
- Ashland Oil's purchase of Southland's 7-11 stations in Minnesota increased its already large share of the Twin Cities market.

These are only several examples of the market shifts that have taken place recently in the United States.

(SLIDE: SALOMON REFINING/MARKETING PROFITABILITY ANALYSIS)

We recently analyzed the downstream performances of 21 major oil firms over the past five years, in part to see if this rationalization has improved the industry's downstream performance. Our review consisted of two parts: a profitability analysis and an operating analysis. We tried to determine how one affected the other.

(SLIDE: FIRMS IN THE SALOMON R&M STUDY)

These are the twenty-one firms in our analysis. These companies are the U.S. refining industry; they control 80 percent of the country's distillation capacity and 85 percent of its conversion capacity. These firms are major factors in the world market; their operations account for 40 percent of world refining capacity.

(SLIDE: FINANCIAL ANALYSIS OF R&M SECTOR--1984-1988)

Our five-year financial analysis has four parts:

- Operating earnings. To calculate this, we took interest expenses and non-operating gains and losses out of segment income. We also "normalized" the firms' tax rates in cases where the downstream business paid no taxes because of corporate-level losses or writeoffs.

- Operating earnings per barrel of product sales. Operating earnings divided by product sales.

- Net income return on identifiable downstream assets. We defined downstream assets to consist of net plant and equipment plus the carrying value of product inventories and the firms' LIFO "cushion."

- Cash flow return on identifiable downstream assets. This somewhat unusual yardstick permits fairer comparisons among firms with refining systems of different ages, we believe. A new refinery, for example, is likely to have higher depreciation and lower book earnings than an older one, even though the cash flow from the two may be the same.

(SLIDE: R&M NET INCOME [EXCLUDING NON-OPERATING GAINS AND LOSSES] OF 21 OIL FIRMS)

This slide summarizes the 21 companies' earnings over the last five years. The sheer size of the firms' downstream income--$33 billion from 1984 through 1988--is impressive: that's more than the American health care, pharmaceutical, retailing and cosmetics industries earned together in the period. These earnings were about evenly divided between U.S. and overseas activities, but the earnings patterns of the two areas differed: overseas income peaked in 1986--the year oil prices collapsed--while U.S. downstream earnings hit a record only last year.

(SLIDE: PROFIT PER BARREL OF OIL PRODUCTS, ETC.)

This translates total downstream earnings into unit profits--operating income divided by oil product sales. On average, the firms' American activities produced after-tax income of 1.9 cents for each gallon of oil products that they sold between 1984 and 1988. The firms' foreign businesses produced identical unit earnings--1.9 cents per gallon--over the whole period, but again, the year-to-year pattern of unit earnings differed between the two areas.

(SLIDE: RETURN ON AVERAGE IDENTIFIABLE ASSETS)

This chart shows the firms' U.S. and overseas downstream earnings as a percent of their average assets. It reinforces the notion that R&M is a business of variable profitability. The period included two good years (1986 and 1988), one bad year (1984) and two so-so years (1985 and 1987). Over the whole period, the 21 companies achieved a 7 percent after-tax return on assets. This was about the same as the after-tax return on short maturity, risk-free investments. Of course, by using financial leverage, the firms could have--and most certainly did--achieve higher returns than that on their equity investments.

(SLIDE: CASH FLOW RETURN ON AVERAGE IDENTIFIABLE R&M ASSETS)

Here we show the firms' cash flow return on assets. This differs from the last slide in a key way: the returns are nearly five percentage points higher throughout--12.2 percent versus 7 percent--because we've added back non-cash charges. Measured this way, refining over the period produced a spread of five percentage points over riskless investments, and a real return (that is, minus inflation) of seven percent.

(SLIDE: FACTORS THAT DETERMINE FINANCIAL SUCCESS)

Here we show the ten firms that produced the best and worst cash flow returns on their downstream assets over the period. Atlantic Richfield was the "best of the best," producing a five-year average cash flow return on assets of 22 percent; and the worst performer in the downstream was Amerada Hess, which had negative cash flow over the period.

What are the operating factors that contribute to financial success in the downstream business?

We think that three main factors separate winners from losers in the R&M industry:

- Market integration, which enables firms to add profit to oil product commodities in several key ways.
- Processing sophistication, which allows firms to process off-spec (and frequently cheap) crudes and/or to produce a relatively high yield of more valuable light products.
- "Single stream" crude slates, which generally boost refinery efficiency as measured by product yields, non-crude operating costs and turn-arounds.

I will focus on the first two factors--market integration and processing sophistication--since they are factors over which refiners have the greatest control.

(SLIDE: MARKETING INTEGRATION--KEY ASPECTS)

Refiners add value to the commodities that leave their facilities by following this simple formula: sell branded products and services; sell them through company-controlled outlets; and locate the outlets in areas of high and growing company market share. What exactly is a branded product? It is, for example, unleaded gasoline sold at an Amoco station? I would describe that as a branded commodity that, to be sure, is more valuable than unbranded gasoline, but not nearly so valuable as a branded product, whose use evokes an image of special properties, such as Amoco Silver (or "Shell 2000" or "Sun Ultra"). In recent years, the most successful U.S. gasoline marketers have transferred their brand names to non-gasoline commodities such as groceries, and I think that the most sophisticated gasoline marketers will eventually create non-gasoline branded products in confections, convenience food, and car care items.

(SLIDE: HOW BEST AND WORST FARE BY MARKET INTEGRATION CRITERIA)

Here we rank the top and bottom five financial performers (in cash flow return on assets) with one another in terms of the market integration criteria that I've described. In the "product orientation" category, big really is better, since only the very large multi-regional firms can undertake the high cost of new product development and roll-out. This could put more distance in the financial performances of the large firms and the small ones in the future.

(SLIDE: INTERNATIONAL INTEGRATED FIRMS RATED BY REFINERY SOPHISTICATION)

In this slide, and the two that follow, we rate the firms in our survey by their U.S. and worldwide refinery sophistication. We have done this by assigning different complexity index numbers to each refining process--for example, index factor of 6 to hydrocracking and only 1 to crude distillation--in each refinery operated by each of the firms. We then weighted the results to produce an overall hardware sophistication index for each firm. The resulting weighted index is a proxy of the firms capability to produce light product and/or to process poor quality (and therefore, cheap) crude oil.

(SLIDE: DOMESTIC INTEGRATED FIRMS RATED BY SOPHISTICATION)

(SLIDE: INDEPENDENT FIRMS RATED BY SOPHISTICATION)

(SLIDE: THE DE-COMMODITIZATION OF THE U.S. R&M INDUSTRY)

I will conclude my historical review by repeating something I said at the beginning of my presentation: merchant, or commodity, refining has been and will continue to be a loser's game--one in which the odds favor the house, not the player. But many firms have caught on to this and have moved away from that to other, more profitable games. This busy slide illustrates the growing division between merchant market refining spreads in the United States and the actual average unit cash flow produced by the U.S. downstream activities of the 21 firms. Finally, we illustrate the unit cash flow line of Amoco to show how well--and how differently from the merchant refiner--one firm can perform by adhering to our downstream dictate: sell branded products and services; sell them in company-controlled outlets, located in areas of high and growing company market share.

(SLIDE: CONCLUSIONS FROM HISTORICAL DATA)

(SLIDE: FUTURE OF THE DOWNSTREAM PETROLEUM INDUSTRY)

What can we say about the future? I think we should keep our eyes on four major factors; these are product demand, environmental issues, plant capacity expansion and the involvement of oil exporting countries in product manufacturing and marketing. These may be the primary determinants of

R&M profitability and earnings growth in America for over the next five years.

(SLIDE: UNITED STATES PRODUCT DEMAND OUTLOOK)

Depending upon crude oil prices, U.S. oil product demand could grow as fast as 1.7 percent per year (low oil price case), or even be slightly negative if oil prices increase faster than inflation over several years. This April, when gasoline prices rocketed following the Exxon Valdez accident, American consumers reacted quickly by trimming consumption and switching from premium gasolines to mid-grades and regular. That episode demonstrated the limit of the industry's pricing flexibility, which may be lower than they were in the 1970s.

(SLIDE: POSITIVE AND NEGATIVE FACTORS IN U.S. DOWNSTREAM OUTLOOK)

I'll discuss both the environmental and capacity issues together, since they are so closely linked. The general view--the one we hear publicly from oil firms, anyway--is that the "bottom line" on the national mandate for cleaner air is that (a) no new refineries will be built in America; (b) existing refineries will suffer static or declining production capacities; and (c) plant operating rates will remain permanently high--that is, 90 percent or higher, and that merchant refining profits, while volatile, will remain on a higher plane than the one they occupied in the 1980s.

I have visited many U.S. refineries over the past few years, and my conclusions differ from this general viewpoint.

First, no new refineries will be built in the U.S. because none are needed (period). This has nothing to do with regulations, clean air or anything of the sort. It merchant refining margins had approached the profitability level of ethylene earlier this year, then the U.S. Gulf Coast would be bursting with new greenfield refinery expansions, as it is now with new ethylene plants.

Second, far from shrinking capacity, new federal and state environmental regulations could have the unanticipated effect of boosting it. Virtually every refinery manager with whom we have spoken has admitted that if forced to spend money to clean up his refinery, he'll spend a little more to raise capacity, too.

Most refineries are "organic"--that is, their production capacities can be stretched with improved catalysts, pumps, heat exchangers and many other pieces of hard ware. It is difficult to gauge the extent of this "capacity creep," but we estimate that it can range from 2 percent to 3 percent per year. There is no refinery in the world whose capacity cannot be boosted at least somewhat--even those in California. My recent visit to Atlantic Richfield's flagship refinery in Los Angeles brought home that point: over the last five years, Arco has steadily boosted the refinery's crude processing capacity from 200,000 b/d to 238,000 daily barrels, a yearly "capacity creep" of 3.5 percent. Industry reference publications list the plant's capacity at 215,000 b/d--nearly 23,000 b/d short of its actual capacity, and have reported it at that level for several years. Furthermore, the plant's bright young managers hope to effect a "stair-step" increase in capacity of 25,000-50,000 b/d in a few years when Southern California's new air quality regulations will require the firm to spend large sums anyway to cut plant emissions.

Finally, throughout most of the 1980s oil companies had no reason to spend large sums on their oil refining systems. Throughout much of the period, capacity was being cut and margins were poor. Since 1986, however, the psychological environment has turned around: firms feel much more optimistic about refining and, as a result, corporate pursestrings are being loosened again for refining investments. Today, it is easier to name the U.S. oil firms that have not announced capacity enhancing capital projects in refining than it is to name those that have.

Finally, I'd like to talk about so-called "clean fuels" for automobiles. This will be brief because the commercial and political viability of methanol, ethanol and the like seems poor. Oil companies, auto manufacturers and consumers have a mutual interest in maintaining the premier position of gasoline as an automotive fuel; "clean fuels"--other than re-formulated gasoline--have no natural political constituencies, and these proposals will die on the vine in my opinion.

(SLIDE: OPEC PYRAMID)

The OPEC countries have stepped up their investments in the downstream business in the past several years. Kuwait purchased Gulf's system in Europe, Saudi Arabia bought half of Texaco's downstream assets in the eastern U.S., and Venezuela acquired interests in three U.S. refineries. Is OPEC, then, a threat to the profitability of refining in the West? The answer, I think--and I admit that I've changed my mind on this--is a qualified no. These countries have purchased existing systems, rather than building new ones (thus, they've not added to capacity). In addition, the buyers have behaved responsibly in setting product prices.

Still, it is terrifying to think what damage a low-cost crude oil exporter could do to downstream industry profits. If that's any threat, it is--as we illustrate it here-to the commodity merchant refiner who competes with no differentiable advantage in proprietary products or location.

(SLIDE: OPEC--HOW THE PLAYERS SHAKE OUT IN REFINING)

This busy slide lists all 13 OPEC countries, and qualitatively rates the likelihood of their becoming more actively involved in refining. I think that only four Persian Gulf countries--Saudi Arabia, Kuwait, Iran and Iraq--have the crude export capability of becoming much larger players in Western refining. The current high cost of purchasing North American refining capacity will keep these countries from making further inroads in our market, however. The OPEC countries are now likely to turn to Europe, where topping refineries can still be had cheaply; however, such acquisitions would have to be followed by major investments in upgrading facilities.

(SLIDE: SUMMARY)

I'll summarize all of my points.

- Consumption (especially of gasoline) seems likely to slow, and capacity could creep upward by two or three percentage points annually.

- U.S. gasoline and other oil products could experience a less favorable supply/demand relationship in the future than in the immediate past (that is, 1988).

- Merchant market spreads, which averaged $3.38 per barrel in 1988, could move in a range of $2.00-$3.00 per barrel in the foreseeable future.

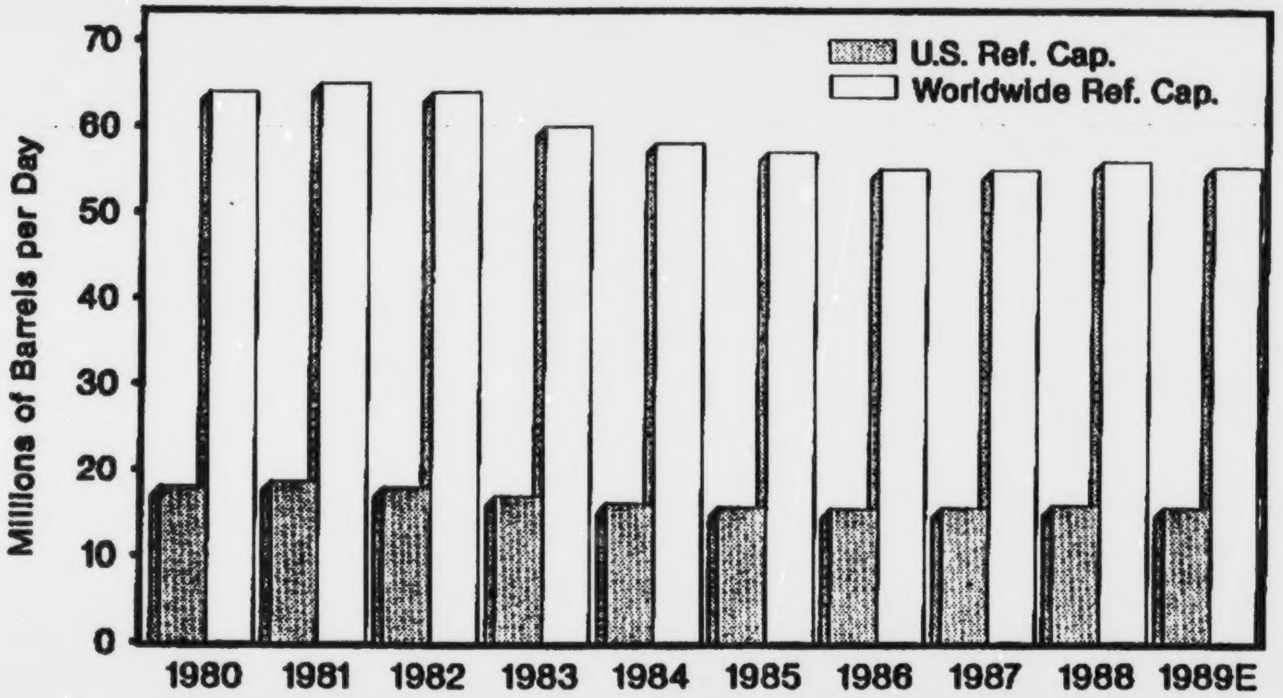
- Geographically protected refiners (California-based facilities, for example) will perform well--at least compared with merchant refiners in transportation-accessible markets.

- OPEC investments in the downstream do not pose any immediate threat to North American refiners; the current high cost of buying into this business will keep out major new investments, but cheap OPEC-produced oil products could come to North America from Europe and Asia.

- The marketing of branded products and services will become even more profitable--and more important to oil firms--in the future. You will see oil companies cross over from convenience groceries and gasoline to proprietary snacks, confections, car care and personal care goods and services.

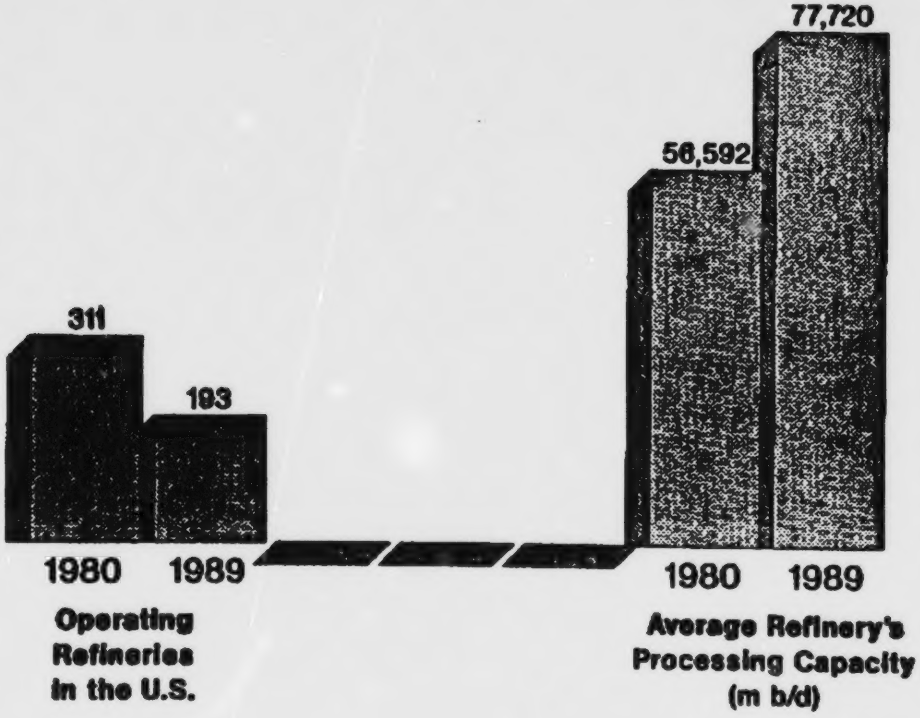
U.S. and World Refining Capacity

1980 Through 1989



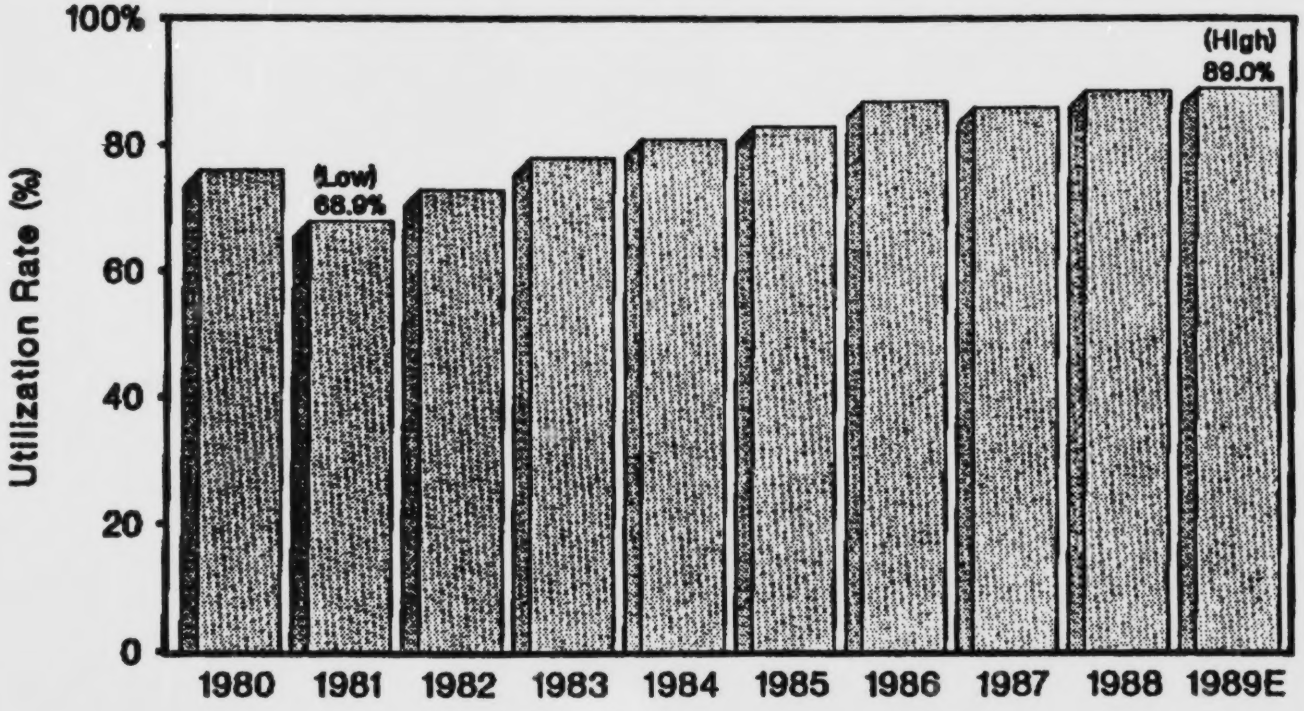
Refinery Population and Processing Capacity of Average U.S. Refinery

1980 and 1989



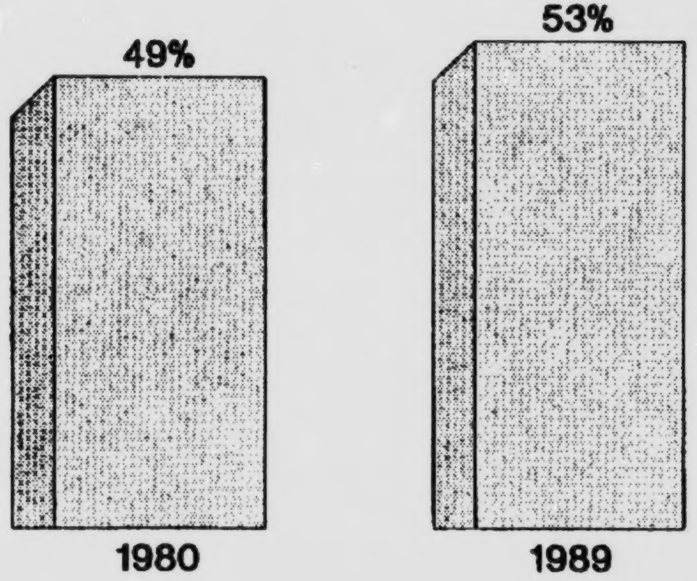
Utilization Rate of U.S. Refinery Operating Capacity

1980 Through 1989



Share of U.S. Operating Refining Capacity Controlled by Eight Largest U.S. Refiners

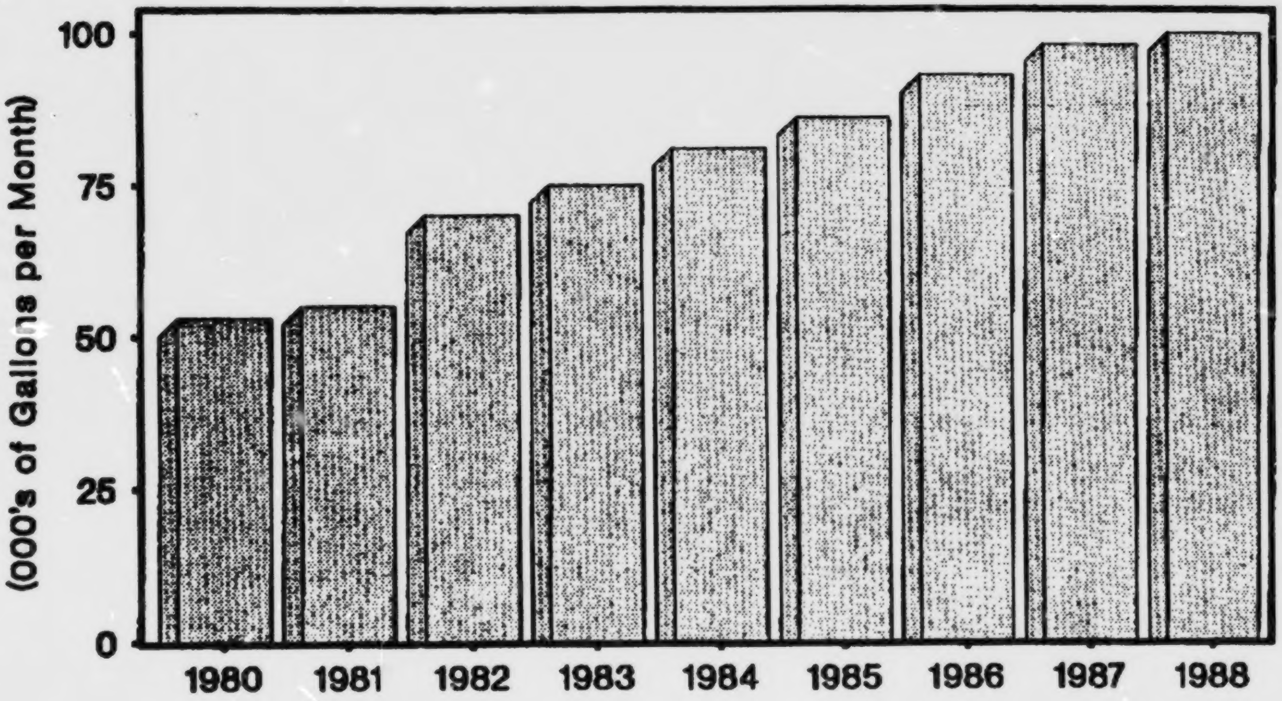
1980 and 1989



Includes BP, Shell, Exxon, Chevron, Mobil, Texaco, ARCO and Amoco

Monthly Sales of Gasoline in Average U.S. Service Station

1980 Through 1988



Salomon R&M Profitability Analysis Has Three Segments

- Downstream Profitability of 21 Oil Firms: 1984 - 1988
- Operational Distinctions Among the Firms
- Future of the Downstream Petroleum Industry

Firms In The Salomon R&M Study

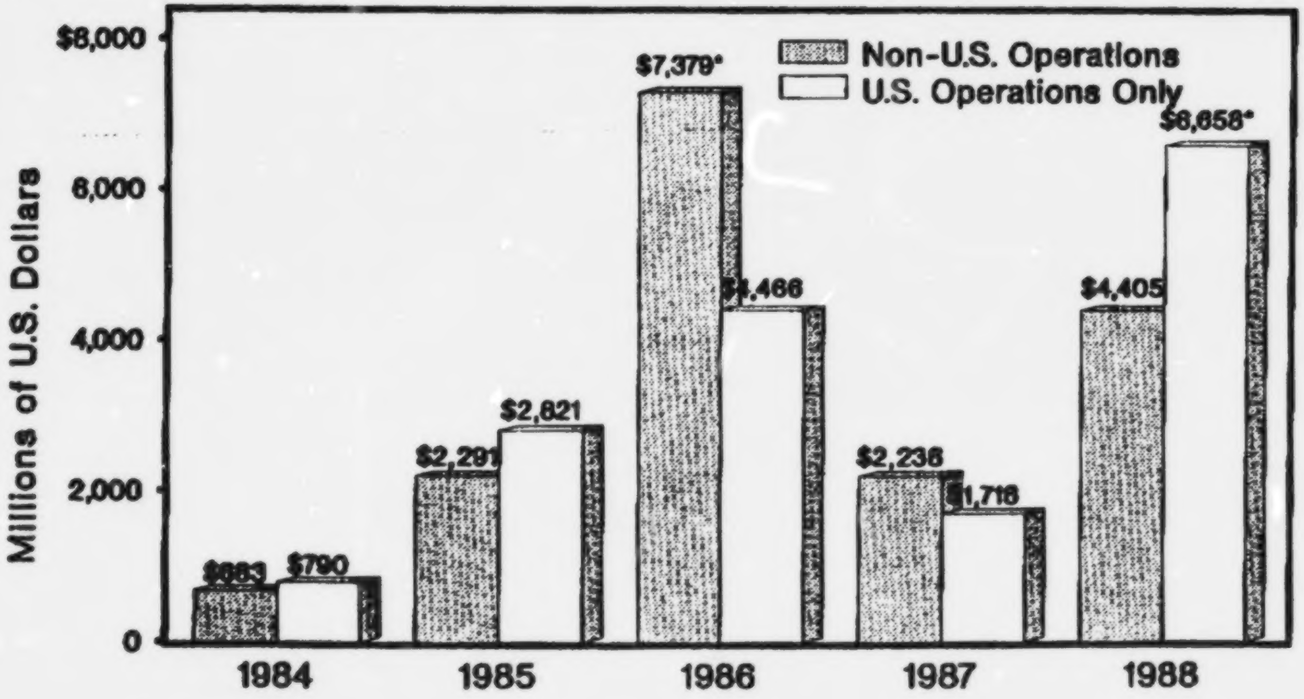
International Integrated Firms	Domestic Integrated Firms	Independent (Domestic) Refiners
BP	Amoco	Ashland
Chevron	ARCO	Diamond
Exxon	Coastal	Total
Mobil	Conoco	
Shell	Hess	
Texaco	Kerr	
	Marathon	
	Murphy	
	Pennzoil	
	Phillips	
	Sun	
	Unocal	

I. Financial Analysis Of R&M Sector
1984-1988

- Net Income Excluding Non-Operating Items
- Profit Per Barrel of Product Sales
- Net Income Return on R&M Assets
- Cash Flow Return on R&M Assets

R&M Net Income (Excluding Non-Operating Gains and Losses) of 21 Oil Firms

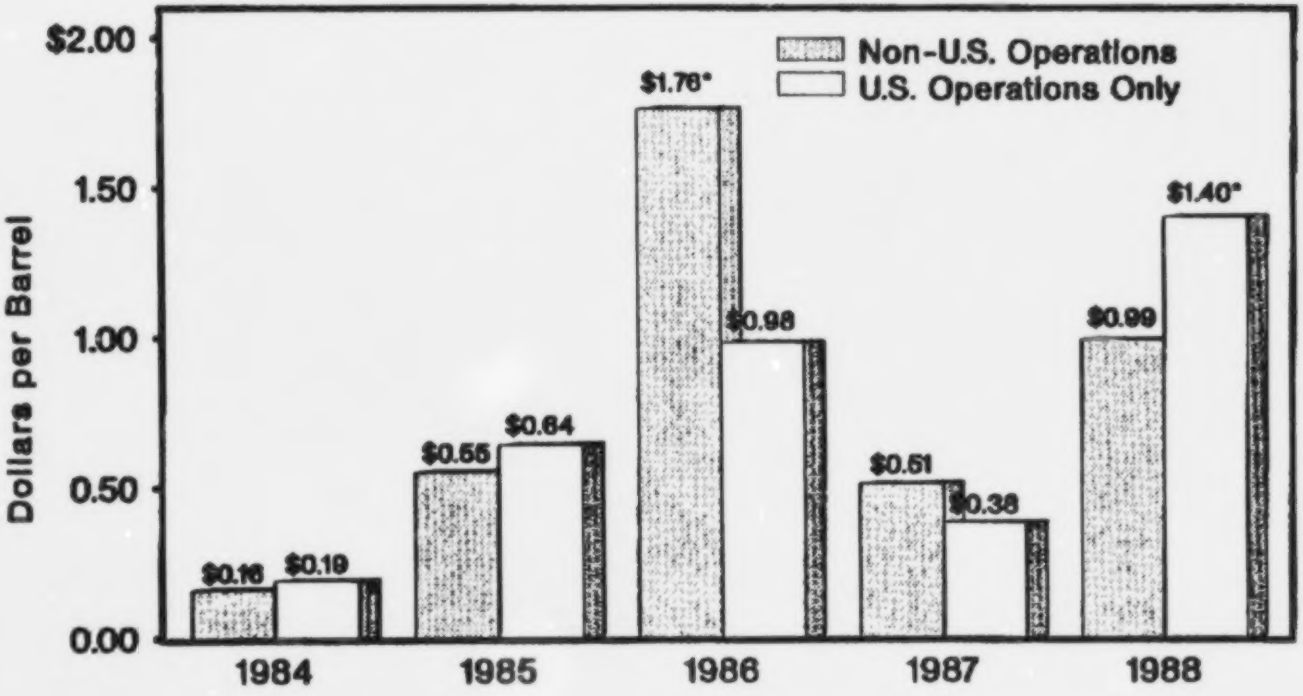
1984 Through 1988



*Indicates record high for geographic sector

Profit Per Barrel of Oil Products Sold by 21 Oil Firms

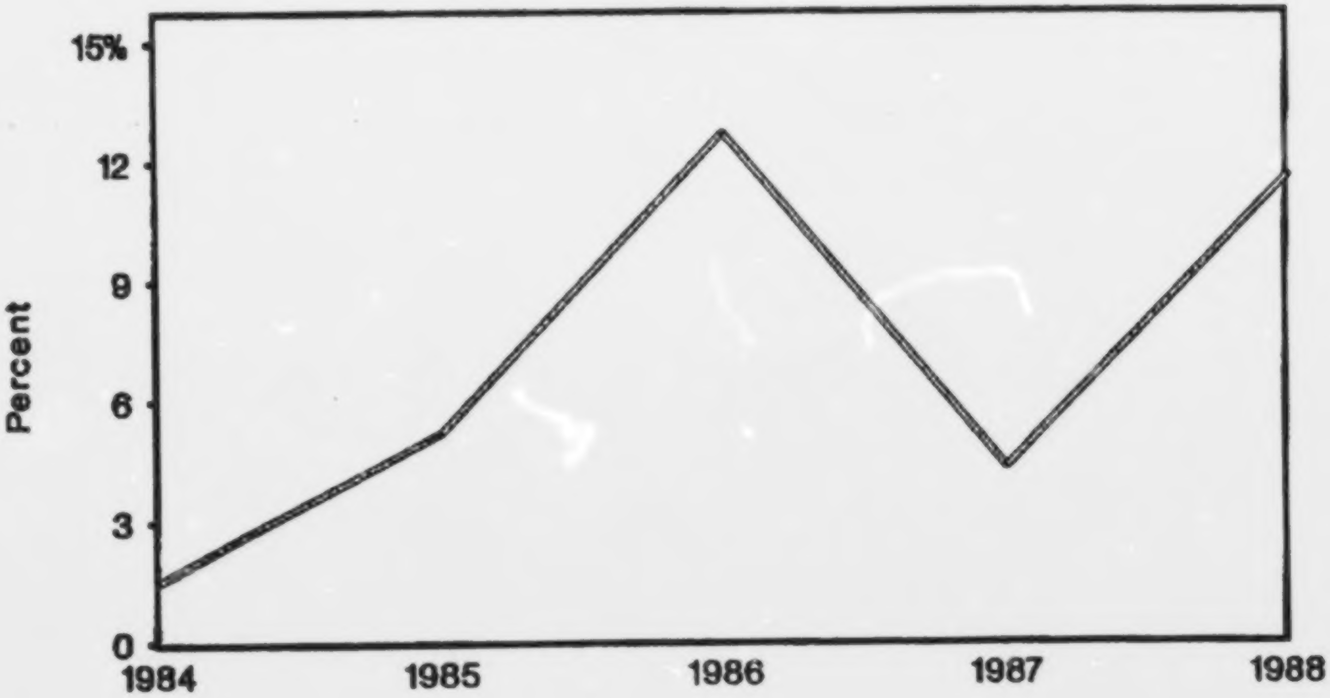
1984 Through 1988



*Indicates record high for geographic segment

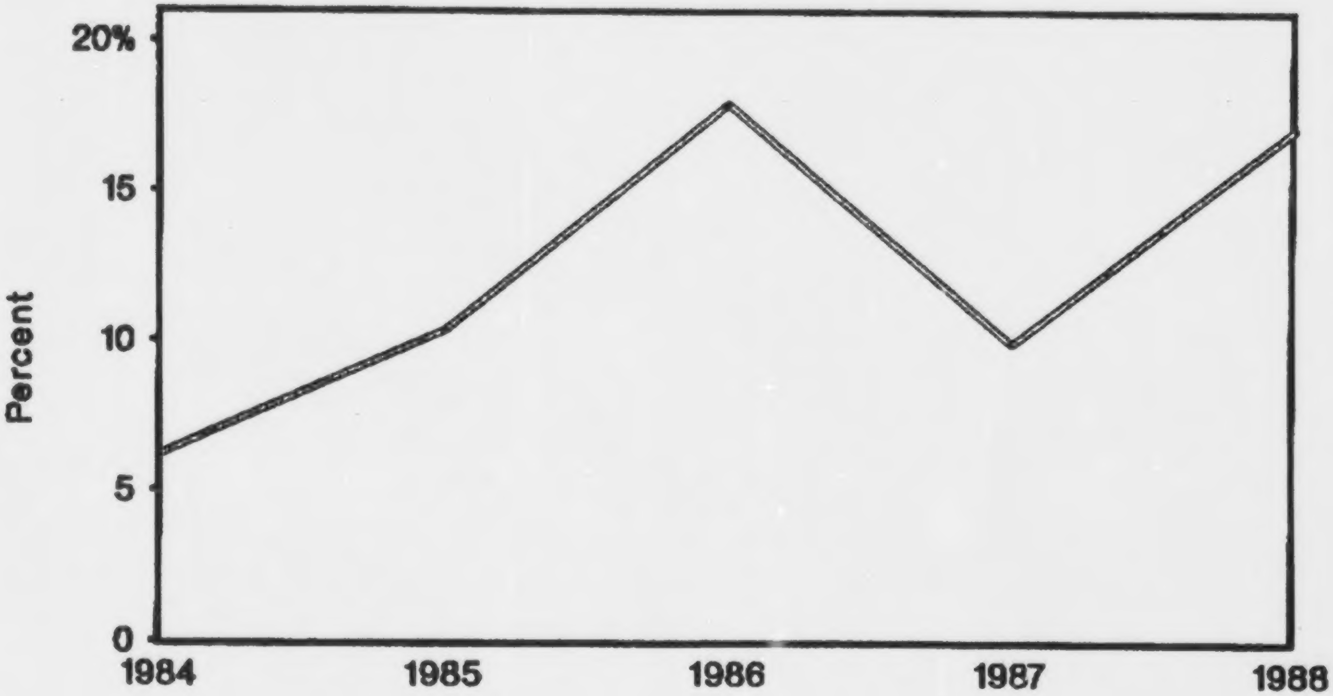
Return of Average Identifiable R&M Assets of 21 Oil Firms - Net Income Basis

1984 Through 1988



Return of Average Identifiable R&M Assets of 21 Oil Firms - Cash Flow Basis

1984 Through 1988



Best and Worst 5-Year Cash Flow Returns on Average R&M Assets - 1984-1988 Period

	5-Year ROA
Best	
Arco	21.9%
Pennzoil	19.9
Shell	16.3
BP	15.7
Diamond	15.4
Worst	
Chevron	10.1%
Sun	9.4
Unocal	9.2
Texaco	8.8
Hess	(0.2)

Factors That Determine Financial Success in R&M

- Marketing Integration
- Processing Sophistication
- "Single-Stream" Crude Slates

Marketing Integration - Key Aspects

- High Proportion of Gasoline Sales Through Company-Controlled and Branded Outlets
- "Product" vs. "Commodity" Sales Image
- High Market Share in Major Metropolitan Areas
- Ancillary Products and Services

How "Best" and "Worst" R&M Firms (by ROA) Fare by Market Integration Criteria

	Pct. of U.S. Gasoline Sold Thru Controlled Stations	Product Orientation	Est. Market Share in Most Import. State
"Best"			
Arco	60%	Low/Medium	23%
Pennzoil	N.A.	Highest	22 (a)
Shell	66	High	15
BP	45	High	26
Diamond	40	Low/Medium	8
"Worst"			
Chevron	30%	Low/Medium	17%
Sun (b)	28	High	10
Unocal	50	Medium/High	11
Texaco	15	Low/Medium	10
Hess	35	Low	5

(a) National share of motor oil market
(b) Before Atlantic refinery purchase

International Integrated Firms Rated By Overall Processing Sophistication

	United States	Outside U.S.	Worldwide Total
Mobil	7.5	4.2	5.4
Exxon	7.5	4.2	5.3
Shell	7.3	3.9	4.8
Texaco	6.9	3.4	4.7
Chevron	4.8	3.4	4.5
BP	6.5	3.3	4.3
Total	**6.5**	**3.8**	**4.8**

Note: The higher the index number, the more sophisticated the refining system.

Domestic Integrated Firms Rated by Overall Processing Sophistication

	United States	Outside U.S.	Worldwide Total
Marathon	7.8	-	7.8
Amoco	7.2	5.0	7.1
Conoco	6.0	8.6	6.8
Unocal	6.7	-	6.7
Phillips	6.3	-	6.3
Sun	6.2	7.3	6.3
ARCO	5.9	-	5.9
Pennzoil	5.7	-	5.7
Kerr	5.7	-	5.7
Murphy	5.6	5.0	5.5
Hess	3.6	-	3.6
Total	**6.3**	**7.2**	**6.3**

Note: The higher the index number, the more sophisticated the refining system.

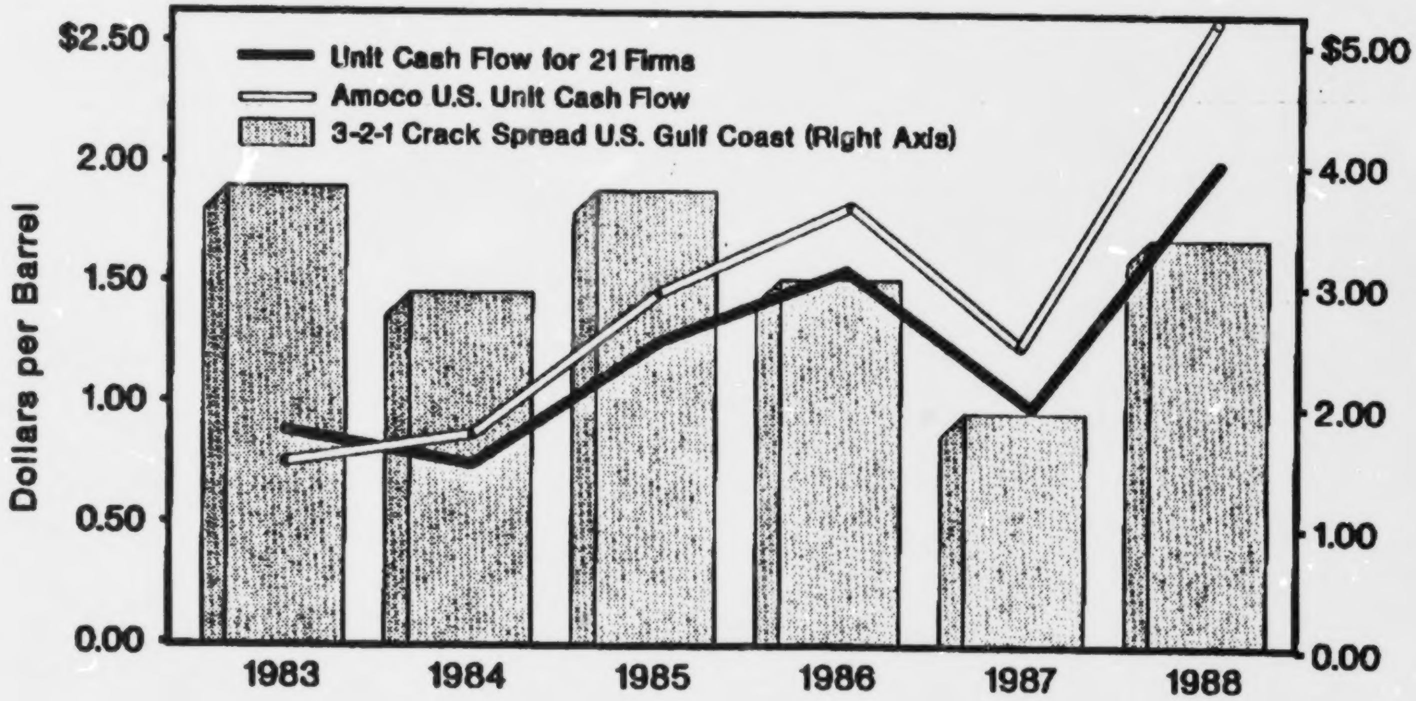
Independents Rated by Overall Processing Sophistication

	United States	Outside U.S.	Worldwide Total
Ashland	7.2	-	7.2
Diamond	6.2	-	6.2
Total	5.6	-	5.6
Total	**6.6**	**-**	**6.6**

Note: The higher the index number, the more sophisticated the refining system.

The "De-Commoditization" of R&M Industry: Gulf Coast 3-2-1 Crack Spread Compared with U.S. Unit Cash Flow of 21 Oil Firms and Amoco

1983 Through 1988



Conclusions from Historical Data

- On average, R/M/T has been a difficult business over the last five years. The 21-company ROA averaged 7.0% in 1984-88 period.
- The industry, however, has many profitable players (e.g. ARCO, Pennzoil and Shell).
- Some of the key determinants of profitability appear to be:
  - Marketing Integration
  - Processing Sophistication
  - "Single-Slate" Crudes

III. Future of the Downstream Petroleum Industry

- Product Demand
- Environmental Considerations
- Plant Construction
- OPEC Involvement

United States Product Demand Outlook

	E. 1989 Demand (m b/d)	1990 - 1994 Avg. Yearly Growth	
		High Oil Price	Low Oil Price
Finished Gasoline	7.3	-1.2%	+0.8%
Leaded	0.9	-5.0	-3.0
Unleaded	6.4	-0.7	+1.3
Regular	4.6	-1.0	+1.0
Premium	1.8	nil	+4.0
Jet Fuel	1.5	nil	+2.0
Distillate Fuel	3.2	+1.0	+2.0
Resid. Fuel	1.3	-5.0	nil
Other	3.9	+1.5	+2.5
Total	**17.2**	**-0.4%**	**+1.7%**

Positive and Negative Factors in U.S. Downstream

Supply

These are positive

- No new greenfield plants probable in U.S.
- New regs on sulfur in diesel - 1994
- Lower summertime RVP standards

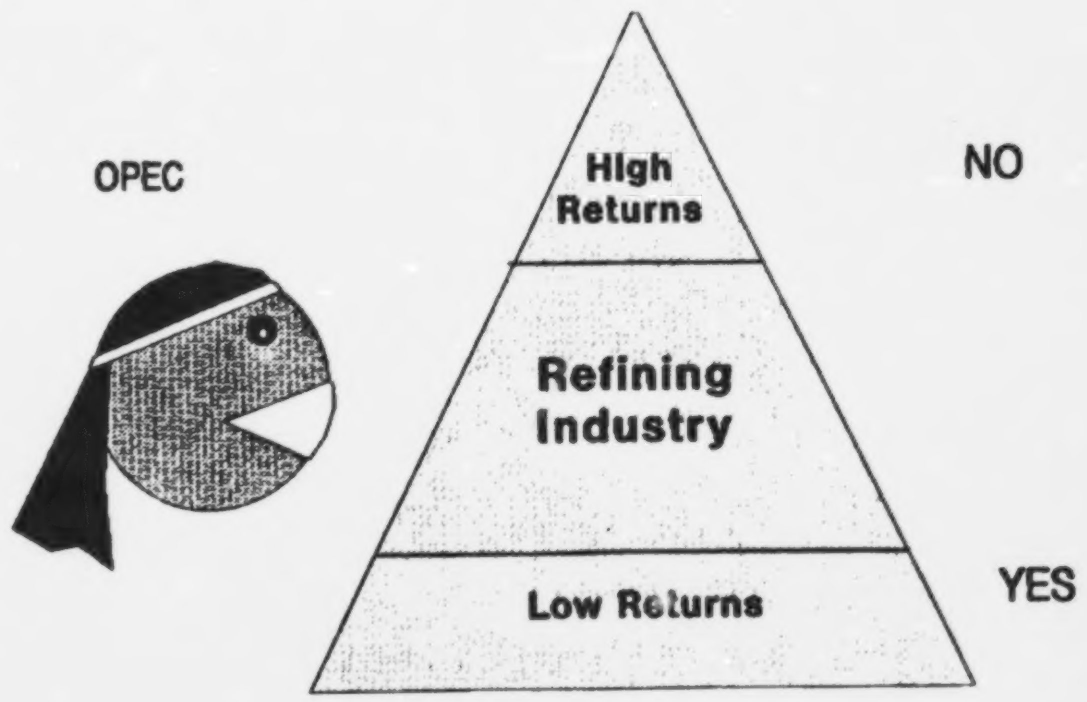
But, these are negative

- Environmental retrofits will coincidentally boost many refiners' capacities (+2%/year nationwide)
- Export-oriented foreign refiners may upgrade

Demand

- Gasoline only small part of DPI
- Receding fears of new oil crisis
- Consumers seem highly sensitive to sudden moves in gasoline prices
- States keep raising excise taxes

Is OPEC Investment in Downstream Assets a Threat to Refining Profits?


OPEC
High Returns
Refining Industry
Low Returns
NO
YES

OPEC - How The Players Shake Out in Refining

Region/Country	Estimated 1989 Crude Production (mb/d)	Current Internal & External Refining Capacity (mb/d)	Theoretical Crude Surplus	Likelihood of New Downstream Investments
Mideast OPEC				
Saudi Arabia	4,772	1,949	2,823	High
Iran	2,856	1,200	1,656	High
Iraq	2,767	336	2,431	High
Kuwait	1,522	647	875	High
United Arab Emirates	1,746	383	1,363	Low
Qatar	391	62	329	Low
Neutral Zone	402	30	372	- -
Subtotal - Mideast	**14,456**	**4,607**	**9,849**	
Other OPEC				
Venezuela	1,683	1,946	(265)	Low
Nigeria	1,608	255	1,351	Low
Indonesia	1,206	1,086	120	Mid
Libya	1,083	235	848	Low
Algeria	693	493	200	Low
Gabon	202	16	186	Low
Ecuador	284	132	152	Nil
Subtotal - Other OPEC	**6,758**	**4,163**	**2,595**	
Grand Total -OPEC	**21,214**	**8,770**	**12,444**	

Summary: Financial Outlook for U.S. R&M Industry

- Gasoline and other light products in the U.S. will experience easing supply/demand relationships versus 1988/1989 because:
  - light product manufacturing capacity could expand 2-3% per year.
  - light product demand may increase only 1.5% annually.
- Merchant market profit spreads, as gauged by "3-2-1 crack spread", could move in the $2.00 - $3.00 per barrel range.
- OPEC is no immediate threat to U.S. R&M profits - but watch out for the long term!
- "Niche" refining may continue to do well.
- Marketing will become even more profitable, due to:
  - Growing market share of nationally branded names
  - High real estate costs present barriers to entry
  - Growth of product-oriented gasoline offerings
  - Add-on products and services

FUTURE INVESTMENT IN THE DOWNSTREAM IN CANADA

Presented by

Gareth R. Crandall
President
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Calgary, Alberta

EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

The focus of my presentation is the investment outlook for the Canadian downstream oil and gas industries, highlighting developments and projects that are currently underway or are in the planning stages. I hope this will provide you with an appreciation of potential investments in the Canadian downstream industries.

(Slide 1) I plan to limit my discussion to the petroleum refining and marketing industry, natural gas processing, natural gas liquids, and petrochemical developments. I also could speak extensively on proposed natural gas pipeline developments, but that subject is being dealt with in great detail by others at this conference. Aside from these gas pipeline projects, we are still anticipating investment potentials in the industries which I just mentioned in the order of $5 billion over the next 5-10 years if most of these projects proceed. Although Canada has always been in a strong resource development mode, with emphasis on exporting raw materials, we can look with some satisfaction to many of these projects, because they involve upgrading of Canadian natural resources into higher value fuel and petrochemical products.

(Slide 2) The petroleum refining and marketing business is a major industry in Canada. The refining industry has gone through a period of rationalization since the early 1980's, but the industry is now faced with growing demand for petroleum products, and a tightening of capacity available to produce these products.

As shown in this slide, we definitely believe there will be capacity shortages in Eastern Canada, unless new capacity is added.

(Slide 3) So far, only Ultramar Canada has made an announcement to add a 10,000 B/D expansion at its refinery in Quebec City. Ultramar is also studying the potential of increasing capacity to 130,000 B/D and to utilize a wider variety of feedstocks. If more capacity is not added, then more products will need to be imported into the Canadian market in order to meet demand.

(Slide 4) Most Canadian refineries rely on light sweet crude to meet their feedstock requirements. As you can see, light crude supplies are declining quite quickly, and replacement supplies in Canada appear to be primarily heavy crudes and bitumen which cannot be readily processed by existing refineries. In fact, we see problems by the mid-1990's in Ontario having enough light crude supplies to meet its requirements unless it begins to import light sweet crude from offshore. With large deposits of heavy crude and bitumen, it is logical for some Canadian refiners to upgrade their facilities to process heavy crudes. The Edmonton refining community would be a logical area, and based on an analysis by Hycarb and its U.S. affiliate, Purvin & Gertz, Inc., we believe that bitumen/light crude price differentials will be in a range of $7-9 per barrel (in 1989 dollars US). We believe this should be sufficient justification to permit residual processing capabilities to be added to existing refineries. However, the industry and especially some industry players face considerable capital shortages, especially for some of the pending environmental impacts, and it may be difficult for the industry to commit to massive investment to utilize heavy crude when it is easier to use existing facilities and simply import more offshore light crude. If such facilities are not added to Canadian refineries, then heavy crude will continue to be exported to U.S. refiners.

(Slide 5) There are many environmental issues which are facing the petroleum refining and marketing industry. Many of them relate to product quality. Already, lead is being phased out of gasoline by some companies and must be phased out by the end of 1990. Vapour pressure of gasoline was reduced in Ontario this summer and a further reduction is expected next summer. This is likely to spread to other areas across the country. Based on expectations from the California market, we expect there will be a limit put on benzene and possibly other aromatics in Canadian gasoline within five years.

By 1993-94, the Canadian refining industry could be required to remove much of the sulphur contained in diesel fuel. This will be required in order for new diesel engines to meet particulate emission standards. In addition to low sulphur levels, the diesel fuel should have a high cetane number and low aromatics content. An estimated $1 billion will have to be expended by the Canadian refining industry in order to produce diesel fuel with a sulphur content of 0.05 wt.%.

Residual fuel oil sulphur content will also be forced down. Recently, Quebec has reduced the maximum sulphur content of heavy fuel oil to 1.5%. Several eastern Canadian utilities are being forced to go offshore to purchase low sulphur heavy fuel oil because additional low sulphur product is not available within Canada. Residual fuel oil sulphur can be reduced only by using sweeter crudes, or by adding residual desulphurization capabilities. Reducing the sulphur in residual fuel oil could also be undertaken at the same time if refineries prepare to process heavier feedstocks.

We also expect there will be pressure to reduce emissions by each refinery source. Reductions in hydrocarbon emissions at refining, marketing and retailing areas will be required. Vapour containment facilities may be required in many storage areas including many urban retail locations. Finally, waste water from refineries will soon have to meet essentially zero contaminants before the water is discharged into existing water systems.

All of these environmental developments will require a considerable expenditure by the refining industry over the next ten years.

(Slide 6) There are several refining project developments currently underway, and many of them include isomerization units and other upgrading to meet unleaded gasoline requirements. The Ultramar expansion is underway, and several refineries are going through miscellaneous tankage upgrading and environmental improvement programs.

(Slide 7) Now I would like to turn my attention to natural gas processing plants which are currently under development. A major expansion of the Cochrane straddle plant will likely be required to serve the PGT expansion by 1993 if it occurs. If the Altamont gas pipeline project proceeds instead, then other straddle plants would likely be required. There are numerous other gas plants which will be required as new gas developments are tied in for export to the U.S. The ERCB is discouraging new grassroots plants, and this should result in some expansions of existing gas plants.

The largest gas development project involves the Caroline area in Alberta. Shell's proposal involves a $700 million development. Husky has filed a competing proposal before the ERCB and its capital expenditures are approaching the same level. Regardless of which project proceeds, this will be a major development for the province of Alberta.

Another project that is currently under development which could be quite significant is Shell Canada's Bearberry development. This is a $65 million pilot plant which will recover sulphur from sour gas containing up to 90% H_2S. If this proves successful, we expect to see more such developments, which are aimed primarily at serving the sulphur export market.

(Slide 8) There are also a number of natural gas liquids developments that are currently underway.

A new de-ethanizer/fractionator at Fort Saskatchewan is planned by Dow and Shell. It would provide feedstock to the proposed Dow ethylene project, and fractionation facilities to process Caroline and other natural gas liquids.

The West-East project sponsored by Interprovincial Pipe Line Company will permit additional gas liquids to be transported from Alberta to Eastern Canada. This project, estimated to cost around $40 million, comprises an injection facility at Edmonton and new storage at Superior.

A new pipeline is planned to be built by Interprovincial Pipe Line Company, which would transport natural gas liquids to serve the Soligaz project in Montreal. This pipeline is expected to cost in the order of $200 million. As well, Soligaz would be providing a new fractionator, storage, distribution, and import terminal facilities for an estimated cost of $200 million.

(Slide 9) We continue to see some significant petrochemical developments occurring in Alberta, as well as in Eastern Canada. In Alberta, there are three proposals to provide new ethylene and other olefin products. The AGEC III ethylene project is currently deferred, but could be reactivated at any time depending on a demand for its products. Dow Chemical is proceeding with its ethylene project in Alberta. This project will be based on ethane and is expected to come onstream in 1993.

Alberta Energy Company is studying an ethylene project in Alberta. If it proceeds as planned, start-up could occur in late 1993. Feedstocks under consideration include ethane and light hydrocarbons from the existing oilsands operations. It is our view that there is sufficient ethane available in Alberta to serve existing plants and these new proposed projects even if they all proceed.

There are many downstream expansions which will likely occur along with increases in ethylene capacity. Along with the Alberta projects proposed by Dow Chemical, Alberta Energy and AGEC, there will be additional derivative projects developed.

(Slide 10) There are two MTBE projects currently under consideration in Canada. The more prominent one so far has been the project proposed by Neste Oy and Petro-Canada at Edmonton, and it would produce MTBE primarily for export to the California market. We expect the status of this project to be fully defined later this year.

A new nitrogen project is under development in Saskatchewan. This project, called SAFERCO PRODUCTS, is a joint venture with the Saskatchewan Government and Cargill Inc. It will produce ammonia and urea for both domestic and export markets.

(Slide 11) In Montreal, Petromont is currently expanding its ethylene plant at Varennes and adding a new polyethylene facility. It also has plans to double its capacity if the Montreal NGL pipeline and Soligaz project is built. This, plus downstream derivative plants, would be a very major investment for the Montreal area.

Because extensive butane supplies will be sent down the proposed pipeline from Sarnia to Montreal, an MTBE project is understudy for utilizing some of the surplus butane that will arrive in Montreal.

There is the potential that new petrochemical facilities could be added in Sarnia. This might involve expansion of existing petrochemical plants, or possibly new plants.

As you know, petrochemical prices have fallen considerably under prices prevalent over the past two years. This business is characteristically cyclical, and the current slowdown might defer some of the petrochemical investments. However, the sponsors of these projects are major companies, and would be expected to take a long-term approach to such developments.

In summary, we can see considerable downstream investment in the Canadian industry. Much of that investment will be aimed at the petrochemical and natural gas liquids businesses. At the same time, primarily driven by shortages of refining capacity, shortages of light crude and increasing environmental pressures, considerable investments will be required in the Canadian refining industry over the next decade.

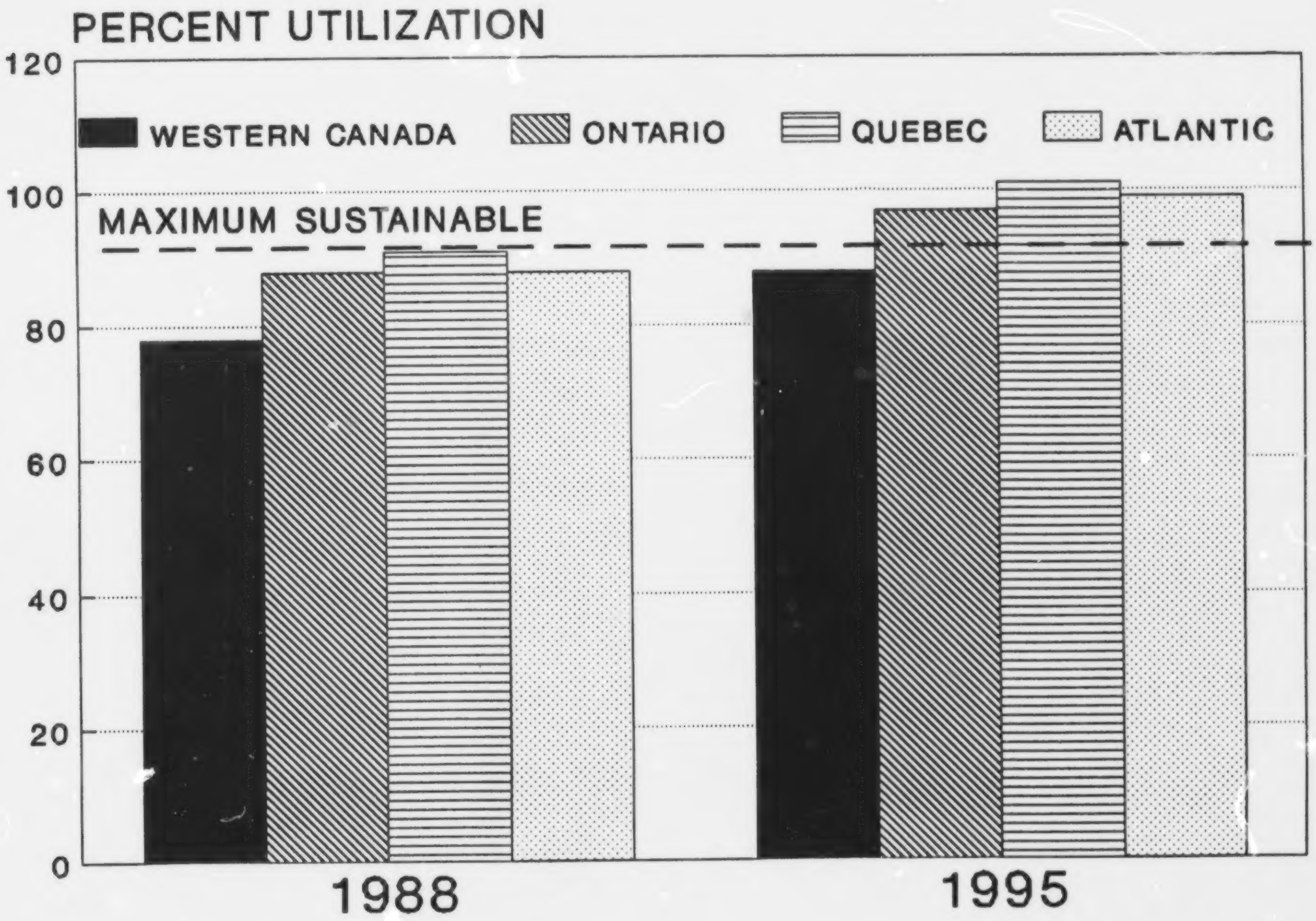
Obviously, for such investments to occur, an environment that is conducive to new investment must be maintained. The Canada-U.S. free trade agreement should go a long way towards encouraging some of these developments. Increased reliance on the marketplace should continue to make Canada a favourable place to invest. Accordingly, we expect there will be increased interest by foreign interests in participating in some of these projects.

SLIDE 1

POTENTIAL DOWNSTREAM INVESTMENTS BY SECTOR

- PETROLEUM REFINERIES
- NATURAL GAS PROCESSING PLANTS
- NATURAL GAS LIQUIDS DEVELOPMENTS
- PETROCHEMICAL DEVELOPMENTS

CANADIAN REFINERIES UTILIZATION

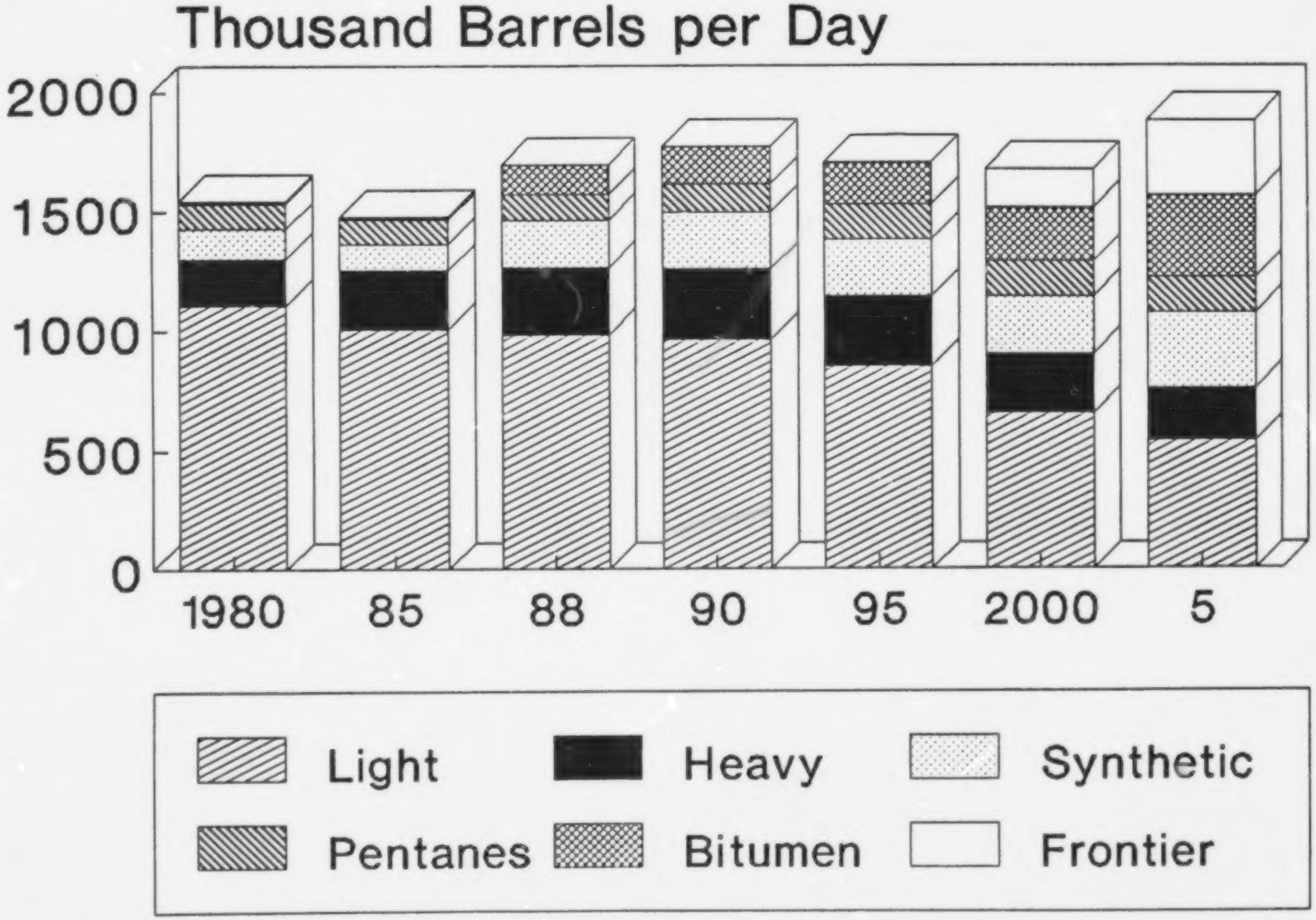


SLIDE 3

PETROLEUM REFINERIES CAPACITY

- CANADIAN REFINERIES UTILIZATION
  - CAPACITY SHORTAGES WILL BE APPEARING IN EASTERN CANADA
  - ULTRAMAR IS EXPANDING IN QUEBEC
  - MORE CAPACITY REQUIRED OR GREATER IMPORTS
- HEAVY CRUDE PROCESSING IS LIMITED
  - CANADIAN LIGHT CRUDE SUPPLY DECLINING
  - WILL REFINERS UPGRADE REFINERIES TO PROCESS HEAVY CRUDE?

CANADIAN CRUDE OIL PRODUCTION



SLIDE 5

ENVIRONMENTAL ISSUES IN PETROLEUM REFINING INDUSTRY

- PRODUCT QUALITY
  - GASOLINE QUALITY
    - Removal of Lead
    - Reduction in Vapour Pressure
    - Limit on Benzene Content
  - DIESEL QUALITY
    - Removal of Sulphur
    - Reduction in Aromatics
  - RESIDUAL FUEL OIL QUALITY
    - Reduction in Sulphur
- OTHER ENVIRONMENTAL
  - Reduction in SO_2 at Source
  - Reduction in Hydrocarbon Emissions at Retail Marketing and Refining Sources
  - Elimination of Contaminants in Waste Water

SLIDE 6

INDUSTRY DEVELOPMENTS

- PROJECTS UNDERWAY
  - PARKLAND INDUSTRIES, BOWDEN
    ISOMERIZATION & HYDROTREATERS (\$9.5 MILLION)
  - PETRO-CANADA, EDMONTON
    ISOMERIZATION (\$67 MILLION)
  - ULTRAMAR, QUEBEC CITY
    ISOMERIZATION UNIT & CRUDE/VACUUM DEBOTTLENECK
  - ULTRAMAR, QUEBEC CITY
    EXPANSION TO 130,000 B/D UNDER STUDY
- INDUSTRY WIDE DEVELOPMENTS
  - UPGRADING TO PRODUCE UNLEADED GASOLINE
  - MISCELLANEOUS TANKAGE UPGRADING
  - ENVIRONMENTAL UPGRADING

NATURAL GAS PROCESSING PLANTS UNDER DEVELOPMENT

- ALBERTA NATURAL GAS COMPANY ($50 MILLION)
  - Expansion of Cochrane for PGT Expansion
  - Planned for 1993
- CAROLINE AREA GAS DEVELOPMENT ($700 MILLION)
  - Proposed by Shell Canada - New Gas Plant at Caroline
  - Proposed by Husky - Expansion of Ram River Plant
  - Proposals before ERCB
  - Startup likely 1992
- SHELL CANADA BEARBERRY FIELD ($65 MILLION)
  - Pilot Project
  - Recovers sour gas with 90% H_2S
  - Planned for late 1990
- NUMEROUS SMALLER GAS PLANTS
  - Tying in new gas for exports
  - Many expansions of existing facilities
  - ERCB discouraging grassroots new plants

SLIDE 8

NATURAL GAS LIQUIDS DEVELOPMENTS

- DE-ETHANIZER/FRACTIONATOR AT FORT SASKATCHEWAN ($120 MILLION)
  - Joint Venture of Dow Chemical and Shell
  - Provides Feedstock for Proposed Dow Ethylene Project
  - Fractionates Caroline and other NGL's
- WEST-EAST NGL PROJECT ($40 MILLION)
  - New Edmonton C3+ Injection Point and Superior Breakout Storage
  - Proposed by Interprovincial Pipe Line Company
  - Detailed Engineering, Planned for 1991
- NEW NGL PIPELINE FROM SARNIA TO MONTREAL ($200 MILLION)
  - Part of Soligaz Project
  - Joint Venture of Interprovincial Pipe Line Company and Soligaz
  - Under Preliminary Engineering, Planned for 1992
- SOLIGAZ PROJECT AT MONTREAL ($200 MILLION)
  - Fractionator, Storage Caverns, Terminal
  - Under Preliminary Engineering, Planned for 1992

ETHYLENE DEVELOPMENTS IN ALBERTA

- ALBERTA AGEC III ETHYLENE PLANT ($500 MILLION)
  - Currently on hold pending firming of markets
- DOW CHEMICAL ETHYLENE PROJECT IN ALBERTA ($450-550 MILLION)
  - Based on Ethane
  - Likely Onstream in 1993
- ALBERTA ENERGY COMPANY ETHYLENE PROJECT IN ALBERTA ($400 MILLION)
  - Based on Ethane and Oilsands $C_2/C_3/C_4$ Feedstock
  - Detailed Study Phase
  - Suggested Startup in 1993
- ALBERTA ETHYLENE DERIVATIVE PROJECTS
  - Expansion of Styrene/Benzene
  - Expansion of polyethylene and ethylene glycol

OTHER PETROCHEMICAL DEVELOPMENTS IN WESTERN CANADA

- MTBE PROJECT BY PETRO-CANADA/NESTE IN EDMONTON ($300 MILLION)
  - 500,000 TONS PER YEAR
  - IN DETAILED STUDY PHASE
  - MOST MTBE WILL BE DESTINED FOR CALIFORNIA MARKET
- SAFERCO PRODUCTS NITROGEN PROJECT IN SASKATCHEWAN ($350 MILLION)
  - JOINT VENTURE OF SASKATCHEWAN GOVERNMENT AND CARGILL LIMITED
  - AMMONIA (1,500 T/D) AND UREA (2,000 T/D)
  - DETAILED STUDY PHASE AND CONTRACTOR SELECTION
  - LIKELY ONSTREAM IN 1992

SLIDE 11

PETROCHEMICAL DEVELOPMENTS IN EASTERN CANADA

- EXPANSION OF PETROMONT IN MONTREAL ($200 MILLION)
  - EXPANSION OF VARENNES FACILITY FROM 220 KT/YR TO 265 KT/YR
  - ADD 200 KT/YR UNIPOL PLANT (HIGH DENSITY POLYETHYLENE)
  - COMPLETION EXPECTED 2ND QUARTER 1991
- FUTURE EXPANSION OF PETROMONT ($500-700 MILLION)
  - CONTINGENT ON SOLIGAZ PROJECT
  - DOUBLE PETROMONT'S ETHYLENE OUTPUT
  - CURRENTLY IN STUDY PHASE, PLANNING FOR 1993-95 STARTUP
- MTBE PROJECT IN MONTREAL
  - CONTINGENT ON SOLIGAZ PROJECT
  - UTILIZE BUTANE FROM WESTERN CANADA
  - IN STUDY PHASE
- OTHER POSSIBLE EXPANSIONS
  - SARNIA ETHYLENE AND DERIVATIVES
  - MONTREAL DERIVATIVE PROJECTS

NATURAL GAS IN NORTH AMERICA - THE NEXT FEW YEARS

presented to the
ANNUAL CONFERENCE
ONTARIO PETROLEUM INSTITUTE
LONDON, ONTARIO
October 17, 1989

The EIGHTH CERI INTERNATIONAL
OIL & GAS MARKETS CONFERENCE
CALGARY, ALBERTA
October 24, 1989

J.K. GRAY
Canadian Hunter
Exploration Ltd.
Calgary, Alberta

Ladies and Gentlemen:

The natural gas industry in North America is going through a period of great change. Change generates opportunity for those who sense the trend of future events with a substantial degree of accuracy, and with energy and determination, act on their conclusions. We are of the opinion that investment in Western Canada's natural gas exploration and production industry represents an unusually attractive opportunity. At Canadian Hunter, have increased our spending to record levels in response to this opportunity.

Changes that are affecting natural gas producers.

1. U.S. natural gas deliverability will fall short of demand this contract year, and, even if delayed by warm weather, regional shortages will certainly occur in 1990/91.

2. The U.S. drilling, exploration and production industry lacks the capability to escalate activity fast enough to

avert the impending deliverability shortage.

3. Canadian natural gas exports to the U.S. will increase to approximately 1.4 TCF in 1989 -- about 8% of total U.S. demand. Further increases in supplies from Canada must await construction of added pipeline capacity.

4. Natural gas consumption on our continent will increase faster than most experts predict. Environmental protection is the highest legislative priority in both Canada and the U.S. We can expect to see new mandated emission standards that can only be met by the increased use of natural gas and electricity.

5. Natural gas prices are set to increase substantially. It should be expected they will double within the next few years.

6. The U.S./Canada Free Trade Agreement prevents discrimination against producers and will result in an improved investment climate and enhanced energy security in both countries.

IMPENDING SHORTFALL IN U.S. DELIVERABILITY

Market expectations and elevated prices generated four or five years of overheated drilling activity in our industry as higher energy prices cut consumption. The unused supply became the much-discussed natural gas deliverability "bubble". For all practical consideration it now is history.

The "bubble" was a product of the marketplace modified by government intervention. The drilling hyperactivity was fuelled by (1) the expectations of higher energy prices and (2) inappropriate regulations which distorted the market and resulted in disordered market decisions.

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In the last three years an annual average of only 6,750 natural gas wells have been drilled in the U.S. Forecasters anticipate a decline to 6000 natural gas wells in 1989.

It would take approximately 12,000 to 14,000 new natural gas wells per year in the U.S. to sustain their present levels of supply.

The implications to natural gas deliverability of the steep decline in natural gas drilling requires the recognition of another reality. In any given year 75% of produced gas comes from wells drilled during the previous ten years and approximately 50% of the gas is sourced from wells drilled during the previous five years. (fig. #2)

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An unavoidable consequence: almost 25% more wells are needed to develop natural gas reserves now than were needed a decade ago.

A sobering fact: annual reserves additions in the U.S. have fallen over 50% since 1981.

Yet another reality: a U.S. deliverability shortage - an actual supply deficit - is deflating the deliverability bubble. Warm weather could delay the moment but won't erase it. Natural gas shortages are inevitable.

Figure #4 prepared from data supplied by TXO Petroleum, clearly demonstrates the rapid decline in surplus supply.

Compounding the emerging imbalance is the growing U.S. demand for natural gas. The greatest single annual growth in gas demand in U.S. history was in 1988. We agree with those who forecast that U.S. demand will reach 22 TCF by 1995, a hefty 20% increase over 1989 consumption levels. Canadian growth in demand was an astonishing 10.2% in 1988.

Several indicators support the expectation that demand will continue to grow:

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We see the approaching U.S. natural gas deliverability shortage lasting some 4 to 6 years. It would take about 12,000 new natural gas wells per year to satisfy the growing U.S. demand --- an increase that approximately doubles the present rate of natural gas drilling. It will happen. But it will take several years.

There are many reasons for the long lead time. A scarcity of quality oil and natural gas prospects is cause enough, but the more serious problem is the erosion of the numbers of required good oil and gas finders. Tens of thousands of skilled exploration and production personnel are gone from our industry. The problem is compounded because a diminishing number of younger people are taking petroleum-related courses in our universities and preparing to enter the business. The necessary drilling prospects have not been mapped. The seismic has not been shot. Field equipment has been lost, cannibalized or scrapped. Inventories of consumabies have dried up. In short, our industry is substantially smaller and weaker than it was a few years ago.

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Changes will continue. In the next century, there will be increased dependence on imported LNG. Already we are considering frontier gas supplies and could be delivering in a decade or so. New sources of natural gas, new supplies of energy, will replace existing production.

CANADIAN NATURAL GAS IMPORTS WILL NOT MATERIALLY OFFSET U.S. DECLINES

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Any increase over 1989 levels will require additional pipeline capacity. Between 3 and 4 Bcf/d of new export pipeline capacity is presently proposed, pending regulatory approval. Some of these lines will not be constructed. In a deregulated environment market forces are the prime determinant of construction priority. For example, the proponents of all these projects must be at risk for the market to work.

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Western Canada has substantial remaining exploration potential for large new natural gas discoveries. There are, however, offsetting factors. A number of our older 'core' natural gas fields are now in decline. Many of these fields have been producing for almost thirty years. Further, there has been a decline in natural gas drilling in Canada in recent years, just as in the U.S.

We hear big numbers describing the shut-in gas wells in Western Canada. We hear that excess deliverability lies ready to be produced. In fact, many of these wells were cased years ago in the expectation of significantly higher gas prices. In my view the conventional estimates of surplus production available from shut-in wells in Western Canada are exaggerated.

But there is a flip side. The prospects in Western Canada for significant new discoveries are exceptional. Two examples head the list. Shell recently discovered between 2 and 3 TCF of sour and liquids-rich natural gas in the Caroline area just north of Calgary. With its partners Shell has announced a $600 MM program that, within two or three years will prepare this discovery for production. (fig. #5)

Our company, Canadian Hunter, together with B.P. America, is developing a 2 to 3 TCF extension of the prolific Alberta Elmworth field projecting northwest into British Columbia. Our new field started producing in quantity last summer and is presently undergoing substantial expansion. Further, our company together with Interhome and Esso, is developing a new 1 TCF discovery that straddles the Alberta-B.C. border southwest of the famous Rainbow Lake oil fields.

These new field developments represent the quality of exploration opportunities that remain in Western Canada. Alberta is one tenth as densely drilled as Texas. As drilling accelerates there will be many more discoveries.

At Canadian Hunter, we are operating the largest program in our history in Western Canada, in excess of $200,000,000, as we position ourselves in this attractive area in advance of an increase in industry activity.

Earlier I mentioned frontier production. In the late 1990's or early in the next century it will be brought to market. The National Energy Board has held hearings on a new pipeline application to connect the 10-12 TCF that is proven on the Mackenzie Delta. Eventually this new pipeline will be built. And remember - Prudhoe Bay is only 350 miles west of the Delta. Perhaps the 25 TCF on the North Slope are closer to market than most appreciate. (fig. #6)

NATURAL GAS CONSUMPTION

Natural gas consumption is increasing. I tend to the view that we are underestimating the impact of the flood of new legislation that will flow from concern over the quality of our environment and its effect on energy and on business. President Bush's amendments to the Clean Air Act have bi-partisan congressional support. The amendments call for significant reduction in SO_2 emissions, a 50% reduction in emissions causing urban pollutants. All of this is to be achieved in 10 years - a very short time.

Concerning So_2 emissions - older power plants are a major source of this acid rain producing pollutant. Co-firing natural gas with coal in older thermal plants is a viable solution to emission reduction. If the 50 largest SO_2 emitting U.S. power plants were to co-fire with 20% natural gas (a feasible undertaking) they would consume 4.1 billion cubic feet per day, a 20% increase in total U.S. natural gas consumption. The Environmental Protection Agency in the U.S. has identified 107 power plants in 18 states that will not meet the tests when this new legislation becomes law.

The implication of new environmental laws will probably be staggering. Adjustment times will be short. Clean and available energy forms will attract premium market prices. New electric generation will be needed. Eventually nuclear energy will again become acceptable but until this happens co-generation facilities using natural gas will be in great demand.

Our planet is experiencing a number of massive structural changes. The political changes taking place in Eastern Europe would have been completely unthinkable even a few months ago. Environmental concern, even fear, is sweeping every country in the world. Green fuels, clean fuels, environmentally friendly fuels will be in great demand. Natural gas heads the list of these favoured fuels and will continue to do so for the forseeable future.

NATURAL GAS PRICES ARE SET TO INCREASE

Supply will tighten in North America and the scarcity will be reflected in higher producer prices. A recent Arthur Anderson survey of 700 oil and gas industry executives concluded that 70% expect natural gas prices to be $3.00/mcf (U.S.) within five years. Others are forecasting $3.50 by 1995, more than double today's wellhead price. As gas becomes more attractive it's quality will demand prices higher than the equivalent oil price. The bulk of the price increases will flow directly to producers.

The cycle of increased demand, resulting in higher gas prices which, in turn, stimulate drilling and increased production will work but it takes time. Unfortunately, as we have mentioned, our industry is not in a position to quickly escalate activities.

There are two threats to the revitalization of our industry.

First, I fear a serious inflation in our costs as activity picks up. Ours is a much smaller industry than the one we operated in the mid-1980's. There is less equipment, lower inventories, fewer people.

Second, history teaches us to beware the damage of the regulators in our midst.

U.S./CANADA FREE TRADE AGREEMENT

We must never underestimate the persistence and destructive capacity of our political and bureaucratic authorities. The U.S. experienced market distorting legislative activities in the pricing and marketing of natural gas dating back to the late 1960's. We Canadians experienced the destructive National Energy Program, the all-time, classic, bureaucratic energy policy blunder.

The great value of the free trade agreement is that it is an important constraint on those who might again attempt to manipulate our energy relationships for their narrow political gain.

The single most important dark cloud on the longer term horizon for our industry is the threat of re-regulation as a political reaction to significantly increased energy prices and supply shortages. I know this is a risk in Canada and I suspect it is a risk in the U.S. Consumers outnumber producers in both countries. The free trade agreement holds at bay the interventionists and isolationists in both countries. This protection will shield investors from damaging legislation with the result of improving energy security for all of our citizens.

The Western Canadian natural gas producing sedimentary basin has the potential for substantially increased production. Our security of supply is directly linked to having a dynamic and aggressive exploration and production industry. Consumers must understand that all markets must compete for available supplies. Consumers won't be bailed out this time by a two-tiered natural gas pricing system as Canadians were in the 1970's and early 1980's. Governments did not intervene to aid producers with price supports when prices collapsed. We took our lumps with the result that many producers failed to survive. As prices rise, no intervention on behalf of consumers will be tolerated. The Free Trade Agreement prohibits a two price regime - this is one of the very desirable attributes of that agreement.

SUMMARY

1. Expect deliverability shortages in the U.S. this year or next. Assume they will last for the next four to six years.

2. Natural gas shortages, present or prospective, will send a market driven signal to our exploration and producing industry telling it to gear up activity. Our response will be considerably slower than would be optimum because our producing industry is both more timid and much smaller than it once was.

3. Our Canadian industry has been damaged by the same negative forces that have hurt the U.S. industry. Supplies of natural gas from Canada will not be available in sufficient quantity to offset the U.S. domestic shortages.

4. There will soon be a flood of environmental legislation that will result in much larger markets for clean fuels, natural gas and electricity.

5. In response to increased market demand the wellhead price of natural gas is expected to more than double in the next few years.

6. The U.S./Canada free trade agreement is a wall of defense for producers that holds at bay the interventionists and isolationists in both countries.

I have defined the elements of an emerging crisis in natural gas supply on this continent. The crisis will not last for long and activity in our industry will resume. Within a few years there will be, perhaps 1500 to 2000 rigs at work in the U.S. drilling some 12,000 gas wells a year. Drilling will increase in Canada. It won't be tomorrow but explorationists and production specialists will again find they are much in demand. Prices will increase. Our industry will not be ready. We will be short of drillable prospects. We will be short of experienced geologists, short of engineers, lacking landmen and geophysicists. There will be opportunities for the nimble and the aggressive.

A plaque on my desk reminds me afresh every working morning that "Crises are Opportunity." The crisis of natural gas supply will soon sweep our continent. Opportunity will be marching in step with it.

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NATURAL GAS WELLS DRILLED
(UNITED STATES)

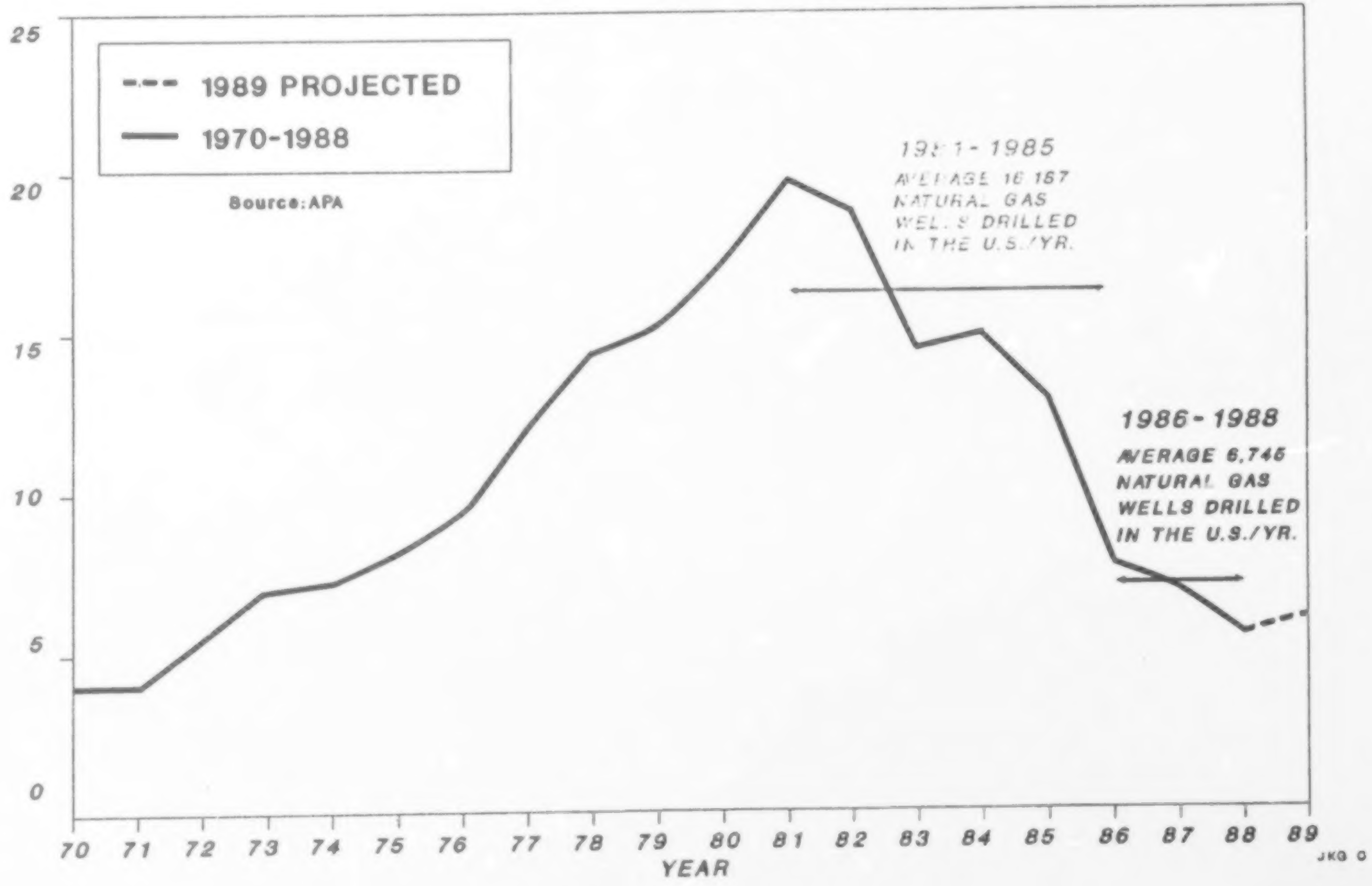
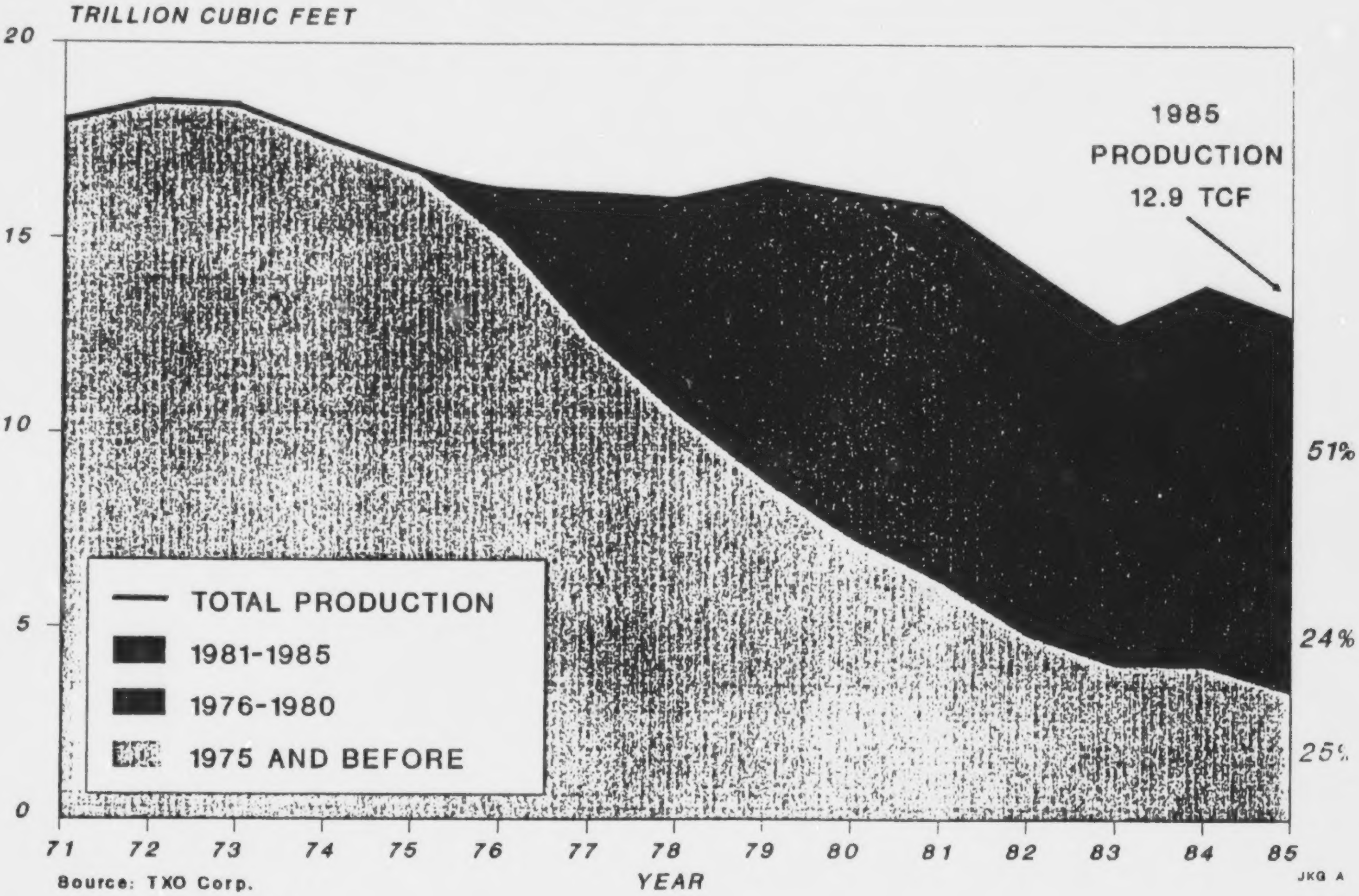


Figure 1

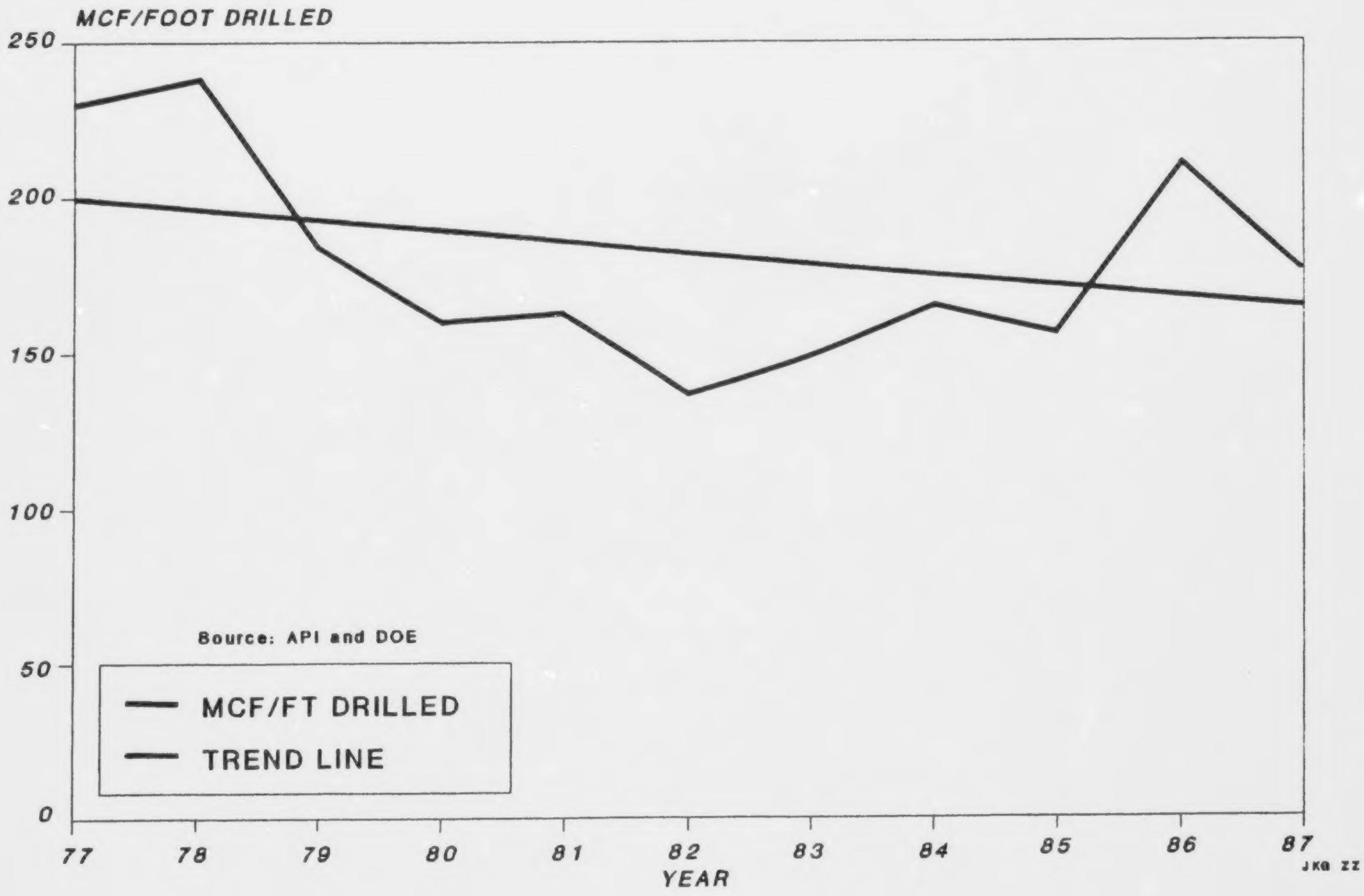
U.S. GAS WELL PRODUCTION
(BY YEAR OF COMPLETION)



Source: TXO Corp.

Figure 2

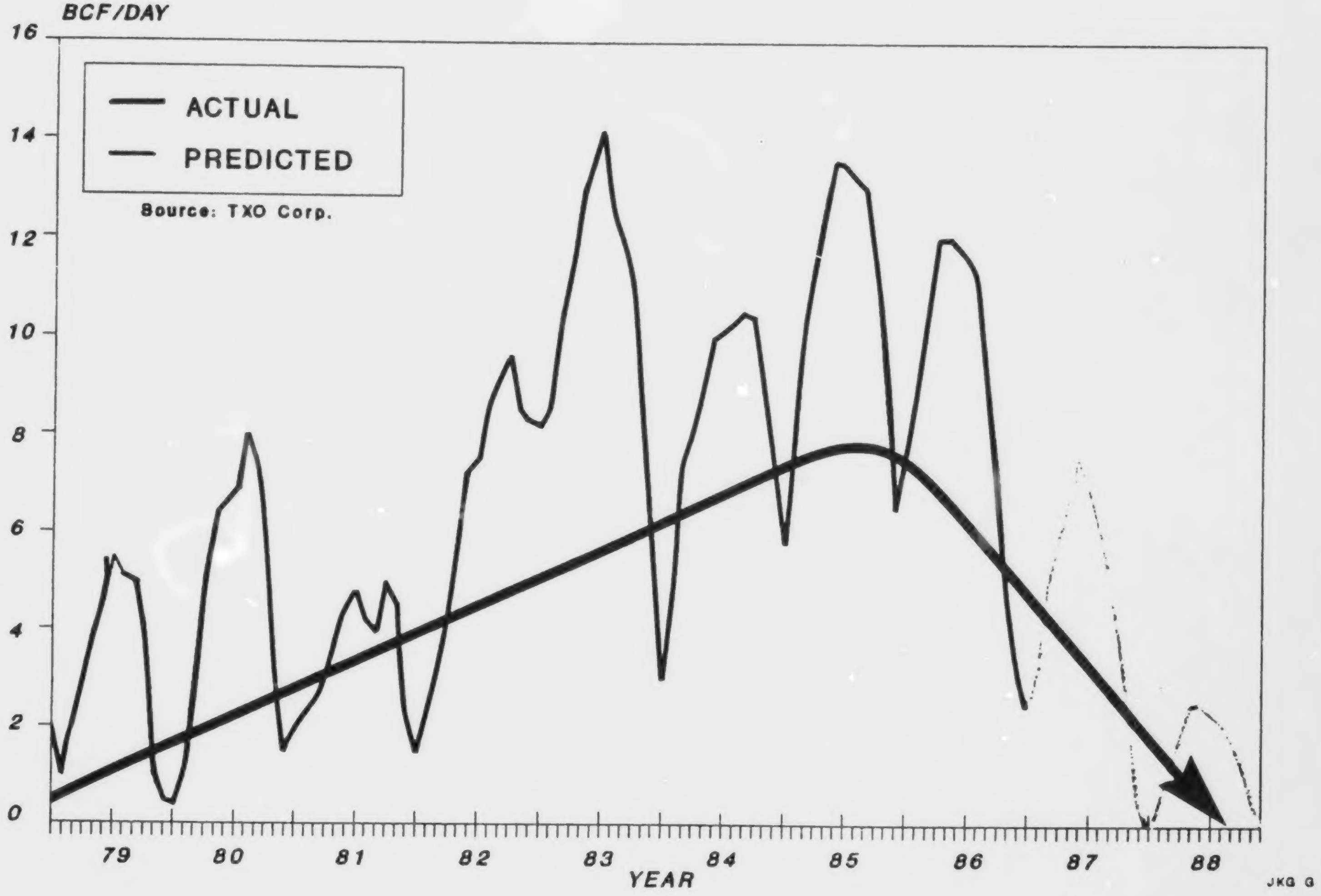
U.S. NATURAL GAS DRILLING RESULTS
(1977 TO 1987)



Source: API and DOE

Figure 3

TOTAL U.S. EXCESS DELIVERABILITY
(BILLION CUBIC FEET/DAY)



Source: TXO Corp.

gure 4

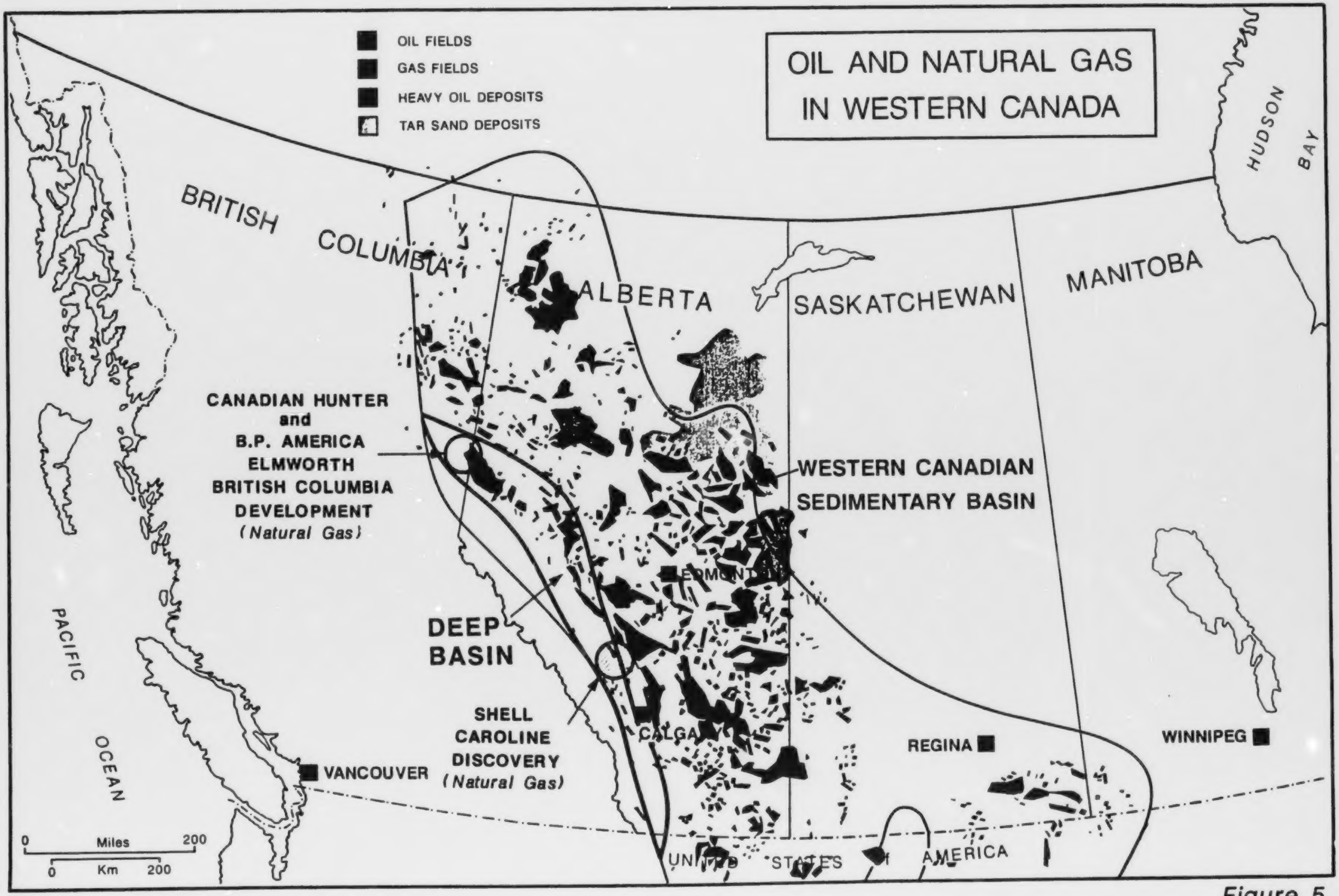

OIL AND NATURAL GAS
IN WESTERN CANADA
OIL FIELDS
GAS FIELDS
HEAVY OIL DEPOSITS
TAR SAND DEPOSITS
HUDSON BAY
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
CANADIAN HUNTER
and
B.P. AMERICA
ELMWORTH
BRITISH COLUMBIA
DEVELOPMENT
(Natural Gas)
WESTERN CANADIAN
SEDIMENTARY BASIN
EDMONTON
DEEP
BASIN
SHELL
CAROLINE
DISCOVERY
(Natural Gas)
CALGARY
REGINA
WINNIPEG
VANCOUVER
PACIFIC
OCEAN
UNITED STATES of AMERICA
0 Miles 200
0 Km 200

Figure 5

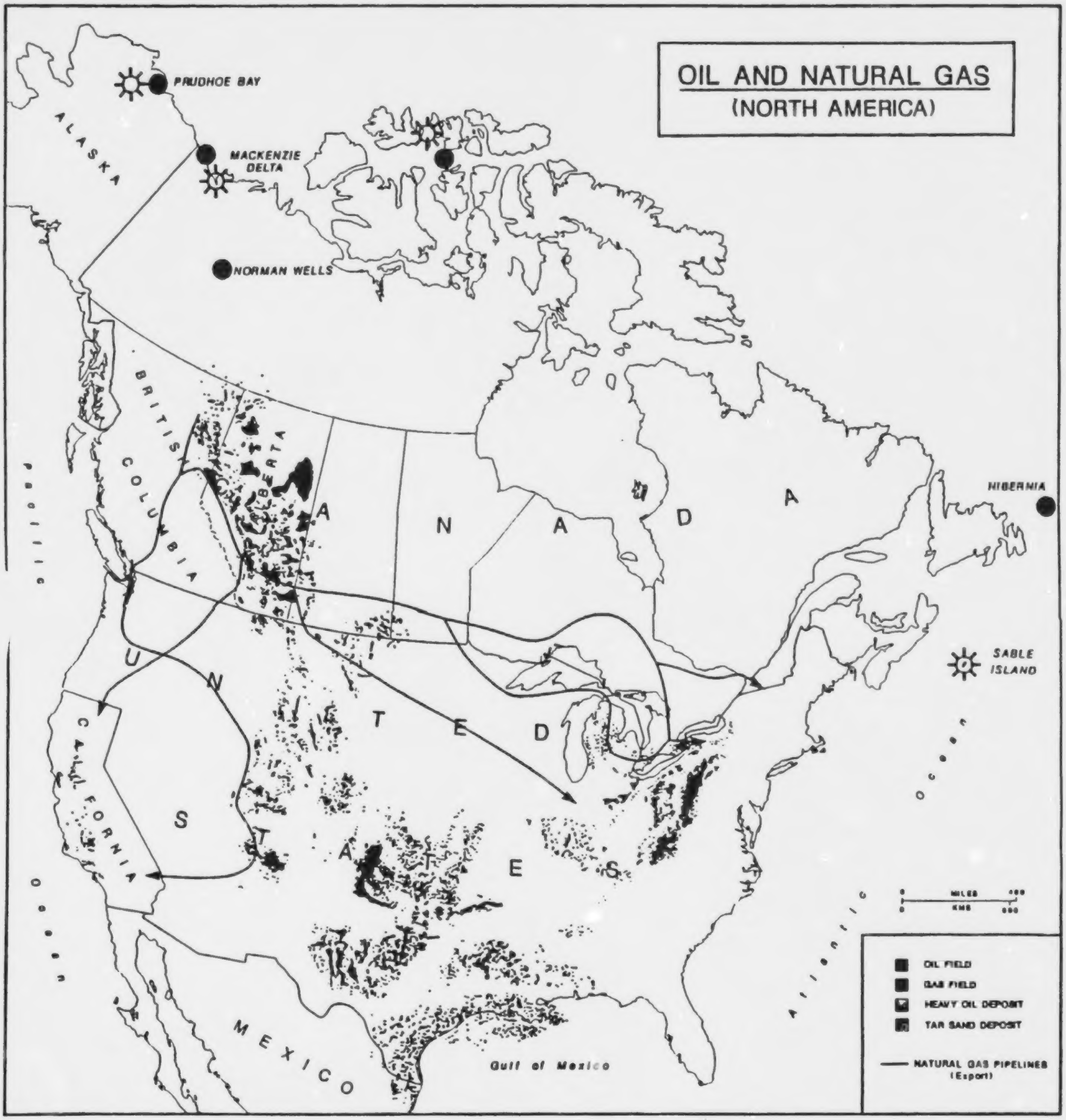

OIL AND NATURAL GAS
(NORTH AMERICA)
PRUDHOE BAY
ALASKA
MACKENZIE DELTA
NORMAN WELLS
BRITISH COLUMBIA
ALBERTA
CANADA
HIBERNIA
SABLE ISLAND
Pacific Ocean
UNITED STATES
CALIFORNIA
MEXICO
Gulf of Mexico
Atlantic Ocean
0 MILES 400
0 KMS 600
OIL FIELD
GAS FIELD
HEAVY OIL DEPOSIT
TAR SAND DEPOSIT
NATURAL GAS PIPELINES (Export)

Figure 6

NATURAL GAS IN NORTH AMERICA - THE NEXT FEW YEARS

presented to the
ANNUAL CONFERENCE
ONTARIO PETROLEUM INSTITUTE
LONDON, ONTARIO
October 17, 1989

The EIGHTH CERI INTERNATIONAL
OIL & GAS MARKETS CONFERENCE
CALGARY, ALBERTA
October 24, 1989

J.K. GRAY
Canadian Hunter
Exploration Ltd.
Calgary, Alberta

Ladies and Gentlemen:

The natural gas industry in North America is going through a period of great change. Change generates opportunity for those who sense the trend of future events with a substantial degree of accuracy, and with energy and determination, act on their conclusions. We are of the opinion that investment in Western Canada's natural gas exploration and production industry represents an unusually attractive opportunity. At Canadian Hunter, have increased our spending to record levels in response to this opportunity.

Changes that are affecting natural gas producers.

1. U.S. natural gas deliverability will fall short of demand this contract year, and, even if delayed by warm weather, regional shortages will certainly occur in 1990/91.

2. The U.S. drilling, exploration and production industry lacks the capability to escalate activity fast enough to

avert the impending deliverability shortage.

3. Canadian natural gas exports to the U.S. will increase to approximately 1.4 TCF in 1989 -- about 8% of total U.S. demand. Further increases in supplies from Canada must await construction of added pipeline capacity.

4. Natural gas consumption on our continent will increase faster than most experts predict. Environmental protection is the highest legislative priority in both Canada and the U.S. We can expect to see new mandated emission standards that can only be met by the increased use of natural gas and electricity.

5. Natural gas prices are set to increase substantially. It should be expected they will double within the next few years.

6. The U.S./Canada Free Trade Agreement prevents discrimination against producers and will result in an improved investment climate and enhanced energy security in both countries.

IMPENDING SHORTFALL IN U.S. DELIVERABILITY

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Western Canada has substantial remaining exploration potential for large new natural gas discoveries. There are, however, offsetting factors. A number of our older 'core' natural gas fields are now in decline. Many of these fields have been producing for almost thirty years. Further, there has been a decline in natural gas drilling in Canada in recent years, just as in the U.S.

We hear big numbers describing the shut-in gas wells in Western Canada. We hear that excess deliverability lies ready to be produced. In fact, many of these wells were cased years ago in the expectation of significantly higher gas prices. In my view the conventional estimates of surplus production available from shut-in wells in Western Canada are exaggerated.

But there is a flip side. The prospects in Western Canada for significant new discoveries are exceptional. Two examples head the list. Shell recently discovered between 2 and 3 TCF of sour and liquids-rich natural gas in the Caroline area just north of Calgary. With its partners Shell has announced a $600 MM program that, within two or three years will prepare this discovery for production. (fig. #5)

Our company, Canadian Hunter, together with B.P. America, is developing a 2 to 3 TCF extension of the prolific Alberta Elmworth field projecting northwest into British Columbia. Our new field started producing in quantity last summer and is presently undergoing substantial expansion. Further, our company together with Interhome and Esso, is developing a new 1 TCF discovery that straddles the Alberta-B.C. border southwest of the famous Rainbow Lake oil fields.

These new field developments represent the quality of exploration opportunities that remain in Western Canada. Alberta is one tenth as densely drilled as Texas. As drilling accelerates there will be many more discoveries.

At Canadian Hunter, we are operating the largest program in our history in Western Canada, in excess of $200,000,000, as we position ourselves in this attractive area in advance of an increase in industry activity.

Earlier I mentioned frontier production. In the late 1990's or early in the next century it will be brought to market. The National Energy Board has held hearings on a new pipeline application to connect the 10-12 TCF that is proven on the Mackenzie Delta. Eventually this new pipeline will be built. And remember - Prudhoe Bay is only 350 miles west of the Delta. Perhaps the 25 TCF on the North Slope are closer to market than most appreciate. (fig. #6)

NATURAL GAS CONSUMPTION

Natural gas consumption is increasing. I tend to the view that we are underestimating the impact of the flood of new legislation that will flow from concern over the quality of our environment and its effect on energy and on business. President Bush's amendments to the Clean Air Act have bi-partisan congressional support. The amendments call for significant reduction in SO_2 emissions, a 50% reduction in emissions causing urban pollutants. All of this is to be achieved in 10 years - a very short time.

Concerning So_2 emissions - older power plants are a major source of this acid rain producing pollutant. Co-firing natural gas with coal in older thermal plants is a viable solution to emission reduction. If the 50 largest SO_2 emitting U.S. power plants were to co-fire with 20% natural gas (a feasible undertaking) they would consume 4.1 billion cubic feet per day, a 20% increase in total U.S. natural gas consumption. The Environmental Protection Agency in the U.S. has identified 107 power plants in 18 states that will not meet the tests when this new legislation becomes law.

The implication of new environmental laws will probably be staggering. Adjustment times will be short. Clean and available energy forms will attract premium market prices. New electric generation will be needed. Eventually nuclear energy will again become acceptable but until this happens co-generation facilities using natural gas will be in great demand.

Our planet is experiencing a number of massive structural changes. The political changes taking place in Eastern Europe would have been completely unthinkable even a few months ago. Environmental concern, even fear, is sweeping every country in the world. Green fuels, clean fuels, environmentally friendly fuels will be in great demand. Natural gas heads the list of these favoured fuels and will continue to do so for the forseeable future.

NATURAL GAS PRICES ARE SET TO INCREASE

Supply will tighten in North America and the scarcity will be reflected in higher producer prices. A recent Arthur Anderson survey of 700 oil and gas industry executives concluded that 70% expect natural gas prices to be $3.00/mcf (U.S.) within five years. Others are forecasting $3.50 by 1995, more than double today's wellhead price. As gas becomes more attractive it's quality will demand prices higher than the equivalent oil price. The bulk of the price increases will flow directly to producers.

The cycle of increased demand, resulting in higher gas prices which, in turn, stimulate drilling and increased production will work but it takes time. Unfortunately, as we have mentioned, our industry is not in a position to quickly escalate activities.

There are two threats to the revitalization of our industry.

First, I fear a serious inflation in our costs as activity picks up. Ours is a much smaller industry than the one we operated in the mid-1980's. There is less equipment, lower inventories, fewer people.

Second, history teaches us to beware the damage of the regulators in our midst.

U.S./CANADA FREE TRADE AGREEMENT

We must never underestimate the persistence and destructive capacity of our political and bureaucratic authorities. The U.S. experienced market distorting legislative activities in the pricing and marketing of natural gas dating back to the late 1960's. We Canadians experienced the destructive National Energy Program, the all-time, classic, bureaucratic energy policy blunder.

The great value of the free trade agreement is that it is an important constraint on those who might again attempt to manipulate our energy relationships for their narrow political gain.

The single most important dark cloud on the longer term horizon for our industry is the threat of re-regulation as a political reaction to significantly increased energy prices and supply shortages. I know this is a risk in Canada and I suspect it is a risk in the U.S. Consumers outnumber producers in both countries. The free trade agreement holds at bay the interventionists and isolationists in both countries. This protection will shield investors from damaging legislation with the result of improving energy security for all of our citizens.

The Western Canadian natural gas producing sedimentary basin has the potential for substantially increased production. Our security of supply is directly linked to having a dynamic and aggressive exploration and production industry. Consumers must understand that all markets must compete for available supplies. Consumers won't be bailed out this time by a two-tiered natural gas pricing system as Canadians were in the 1970's and early 1980's. Governments did not intervene to aid producers with price supports when prices collapsed. We took our lumps with the result that many producers failed to survive. As prices rise, no intervention on behalf of consumers will be tolerated. The Free Trade Agreement prohibits a two price regime - this is one of the very desirable attributes of that agreement.

SUMMARY

1. Expect deliverability shortages in the U.S. this year or next. Assume they will last for the next four to six years.

2. Natural gas shortages, present or prospective, will send a market driven signal to our exploration and producing industry telling it to gear up activity. Our response will be considerably slower than would be optimum because our producing industry is both more timid and much smaller than it once was.

3. Our Canadian industry has been damaged by the same negative forces that have hurt the U.S. industry. Supplies of natural gas from Canada will not be available in sufficient quantity to offset the U.S. domestic shortages.

4. There will soon be a flood of environmental legislation that will result in much larger markets for clean fuels, natural gas and electricity.

5. In response to increased market demand the wellhead price of natural gas is expected to more than double in the next few years.

6. The U.S./Canada free trade agreement is a wall of defense for producers that holds at bay the interventionists and isolationists in both countries.

I have defined the elements of an emerging crisis in natural gas supply on this continent. The crisis will not last for long and activity in our industry will resume. Within a few years there will be, perhaps 1500 to 2000 rigs at work in the U.S. drilling some 12,000 gas wells a year. Drilling will increase in Canada. It won't be tomorrow but explorationists and production specialists will again find they are much in demand. Prices will increase. Our industry will not be ready. We will be short of drillable prospects. We will be short of experienced geologists, short of engineers, lacking landmen and geophysicists. There will be opportunities for the nimble and the aggressive.

A plaque on my desk reminds me afresh every working morning that "Crises are Opportunity." The crisis of natural gas supply will soon sweep our continent. Opportunity will be marching in step with it.

NATURAL GAS WELLS DRILLED
(UNITED STATES)

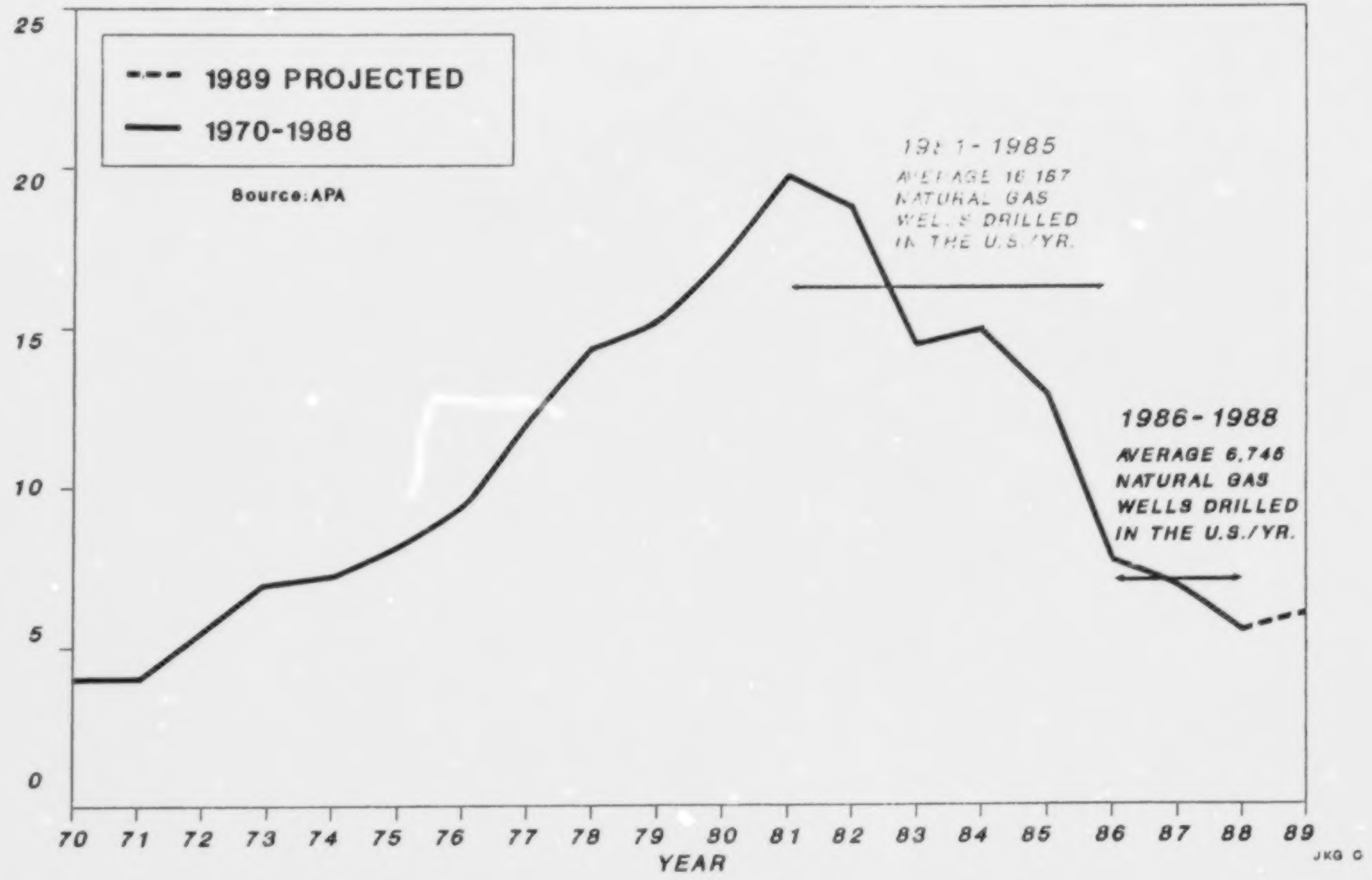
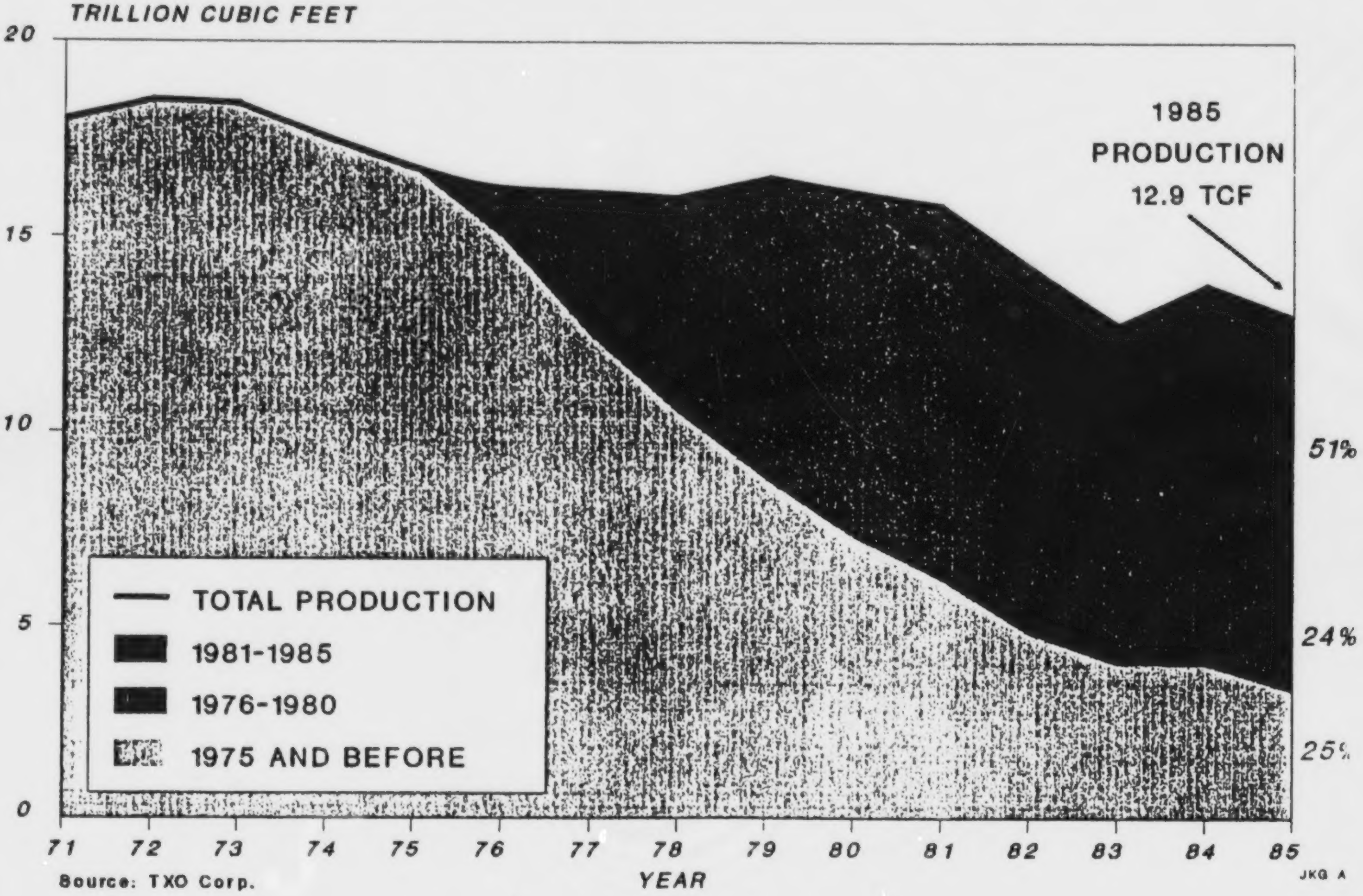


Figure 1

U.S. GAS WELL PRODUCTION
(BY YEAR OF COMPLETION)

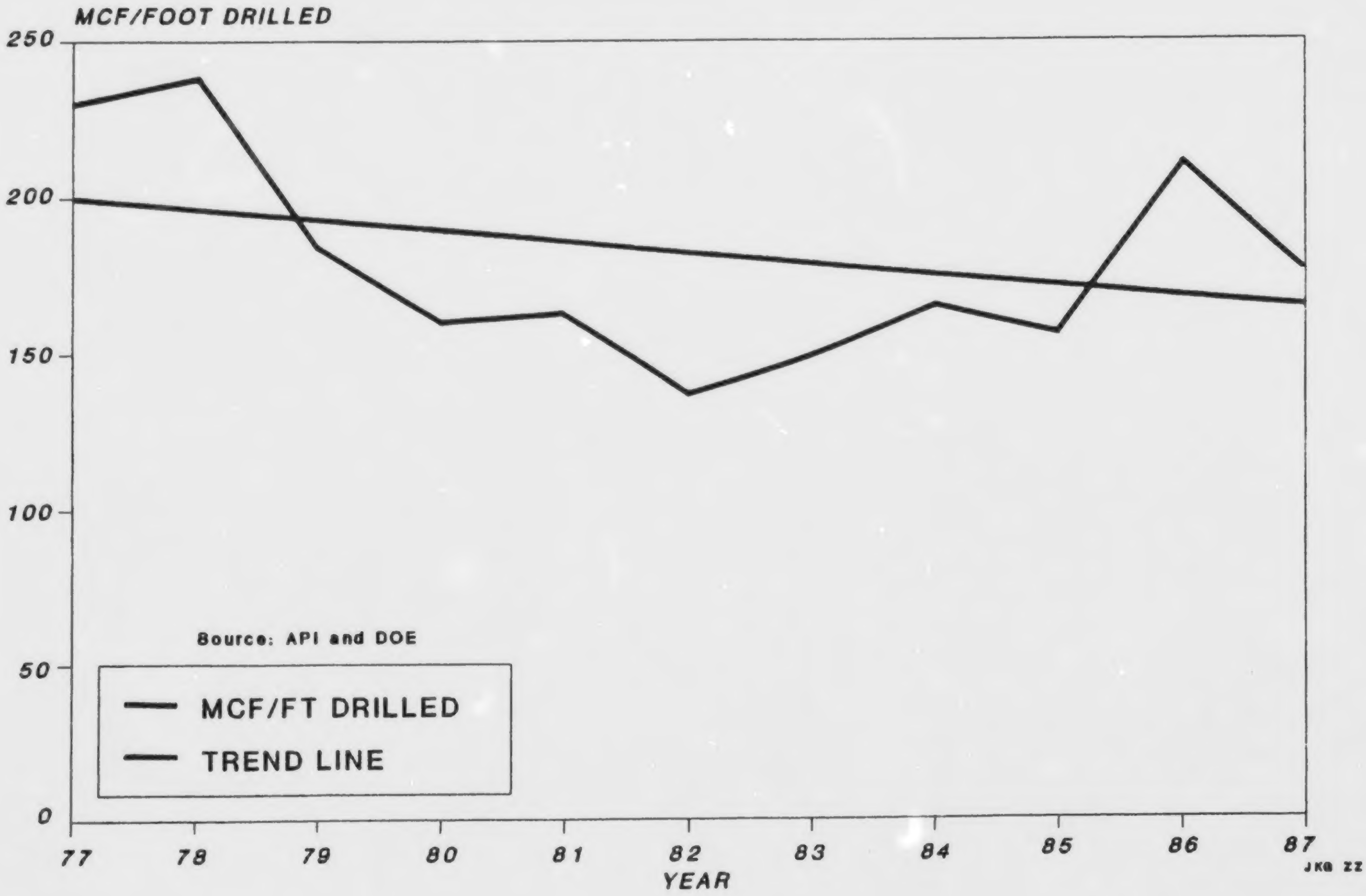


Source: TXO Corp.

Figure 2

U.S. NATURAL GAS DRILLING RESULTS

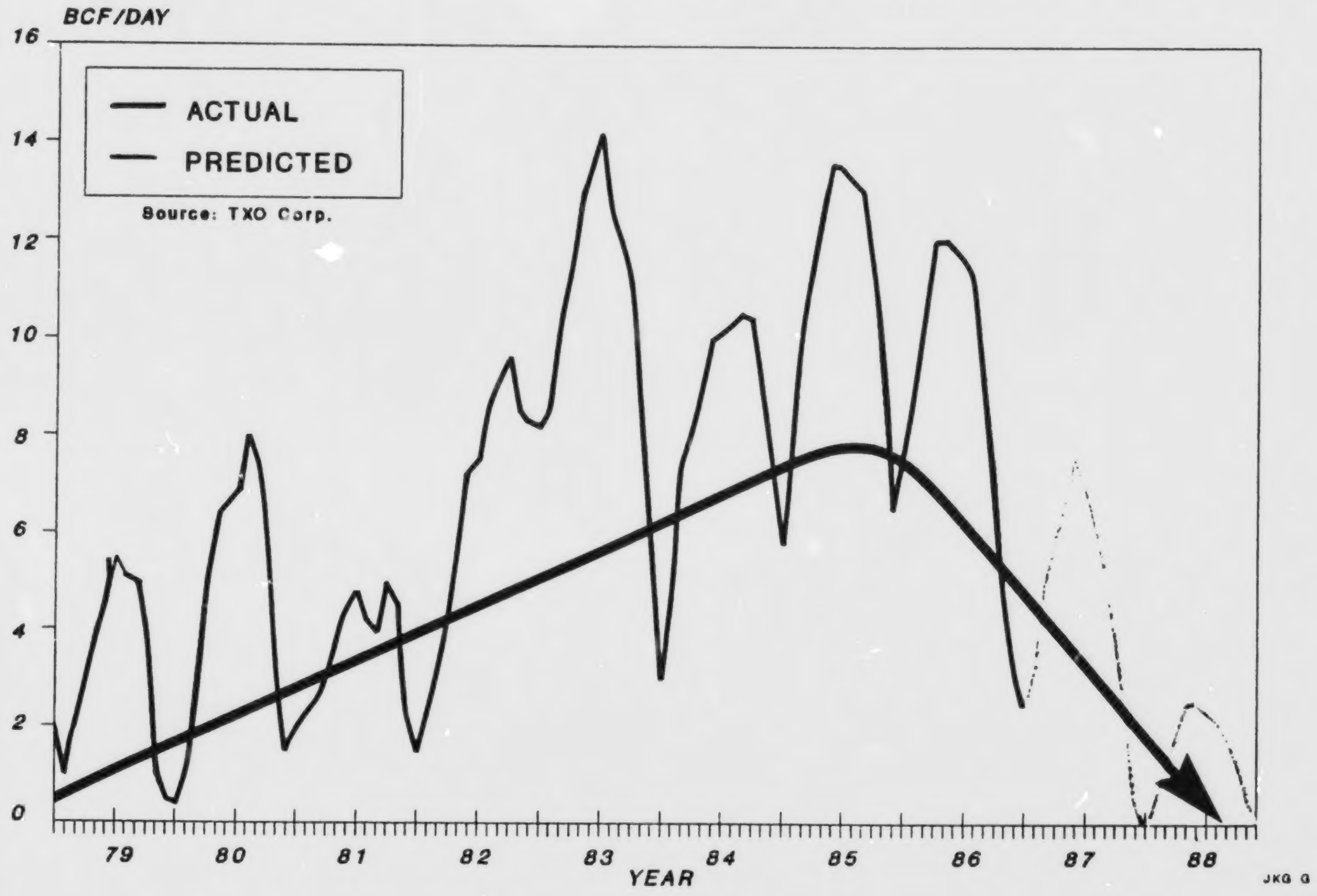
(1977 TO 1987)



Source: API and DOE

Figure 3

TOTAL U.S. EXCESS DELIVERABILITY
(BILLION CUBIC FEET/DAY)



Source: TXO Corp.

ure 4.

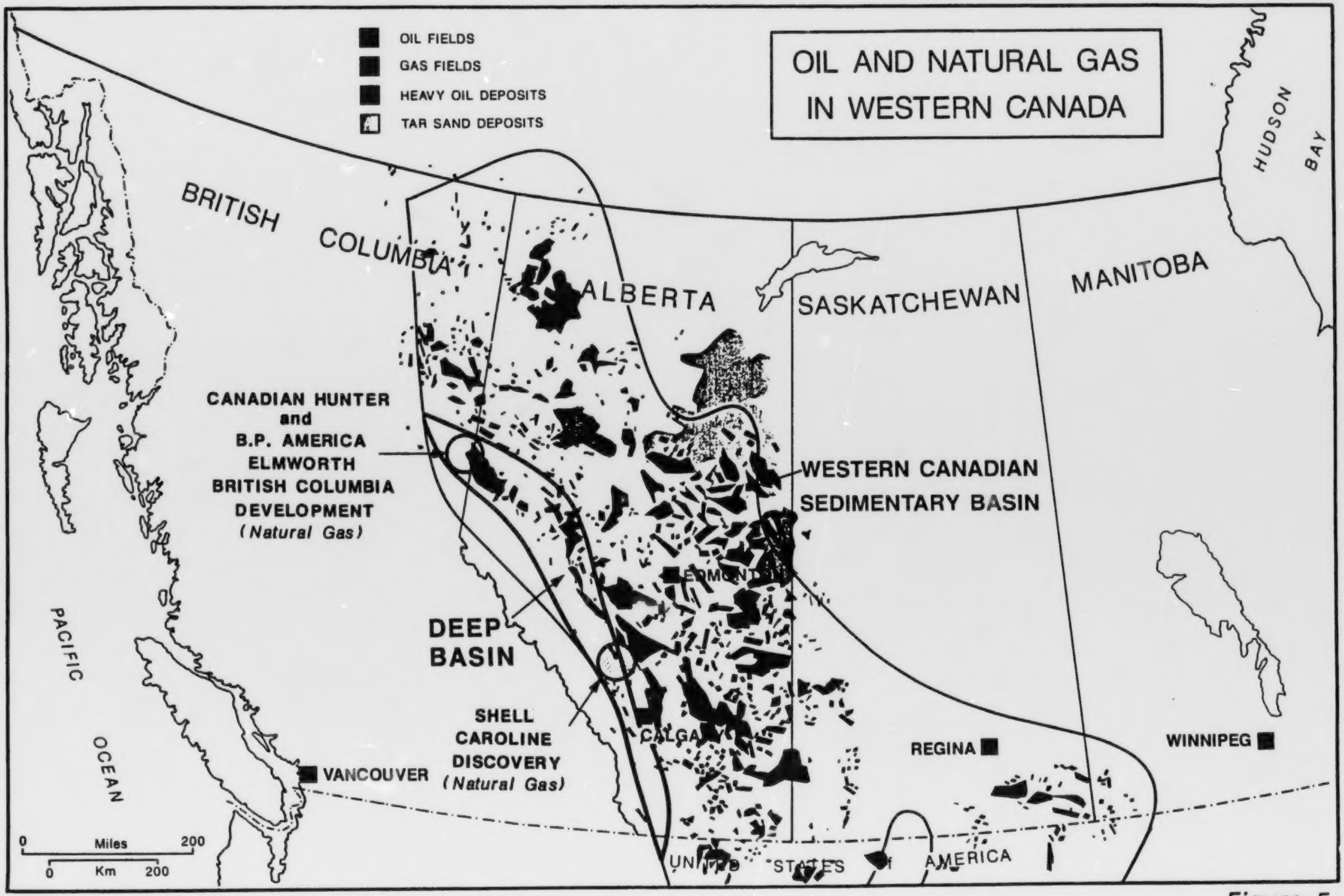

OIL AND NATURAL GAS
IN WESTERN CANADA
OIL FIELDS
GAS FIELDS
HEAVY OIL DEPOSITS
TAR SAND DEPOSITS
HUDSON BAY
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
CANADIAN HUNTER
and
B.P. AMERICA
ELMWORTH
BRITISH COLUMBIA
DEVELOPMENT
(Natural Gas)
WESTERN CANADIAN
SEDIMENTARY BASIN
EDMONTON
DEEP
BASIN
SHELL
CAROLINE
DISCOVERY
(Natural Gas)
CALGARY
REGINA
WINNIPEG
VANCOUVER
PACIFIC
OCEAN
UNITED STATES of AMERICA
0
Miles
200
0
Km
200

Figure 5

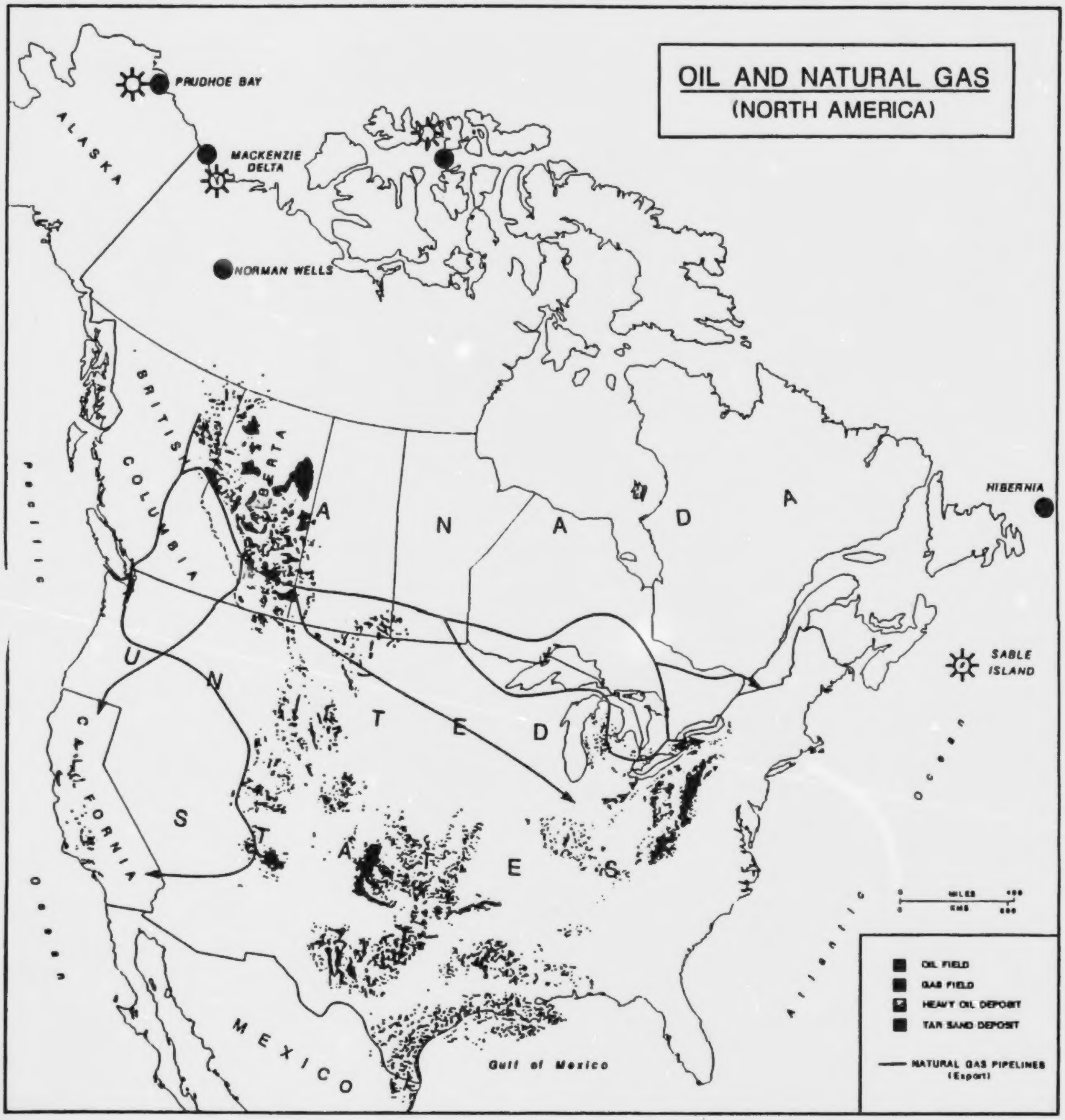

OIL AND NATURAL GAS
(NORTH AMERICA)
PRUDHOE BAY
ALASKA
MACKENZIE DELTA
NORMAN WELLS
BRITISH COLUMBIA
ALBERTA
CANADA
HIBERNIA
SABLE ISLAND
Pacific Ocean
UNITED STATES
CALIFORNIA
MEXICO
Gulf of Mexico
Atlantic Ocean
0 MILES 400
0 KMS 600
OIL FIELD
GAS FIELD
HEAVY OIL DEPOSIT
TAR SAND DEPOSIT
NATURAL GAS PIPELINES (Export)

Figure 6

REMARKS FOR
THE EIGHTH CERI INTERNATIONAL OIL AND GAS MARKETS CONFERENCE
OCTOBER 22/24, 1989 - CALGARY, ALBERTA

ONTARIO GAS MARKET DEVELOPMENTS

BY

J. C. HUNTER
VICE-PRESIDENT, GAS SUPPLY
UNION GAS LIMITED, CHATHAM, ONTARIO

SLIDE 1
INTRODUCTION

LADIES AND GENTLEMEN, IT IS A PLEASURE TO BE HERE TODAY WITH MY FELLOW PANELISTS TO, HOPEFULLY, ASSIST YOU IN PREPARING FOR ENERGY MARKETS OF THE COMING DECADE.

SLIDE 2
TOPIC OUTLINE

MY PARTICULAR TOPIC WILL BE WITH RESPECT TO NATURAL GAS MARKETS, WITH THE EMPHASIS ON ONTARIO.

MY REMARKS WILL BE DIVIDED INTO FOUR AREAS. I WILL FIRST GIVE AN OVERVIEW OF THE PRE-DEREGULATION SCENE BECAUSE I THINK UNDERSTANDING WHERE WE WERE IS IMPORTANT TO UNDERSTANDING WHERE WE ARE GOING. I WILL THEN REVIEW THE ACTIVITIES AND EVENTS THAT HAVE HAPPENED SINCE DEREGULATION OCCURRED. THIRDLY, I WILL PROVIDE MY VIEWS ON WHERE THE FUTURE IS LIKELY TO TAKE US IN GAS MARKETING, AND LASTLY I PROPOSE TO MAKE SOME SPECIFIC RECOMMENDATIONS FOR BOTH BUYERS AND SELLERS.

SLIDE 3
"THE WAY WE WERE"
THE PRE-DEREGULATION SCENE 1975-1985

AS WE SIT HERE TODAY, IT SEEMS ALMOST DIFFICULT TO REMEMBER WHAT LIFE WAS LIKE IN THIS BUSINESS PRE 1985. SOME SAY GOOD RIDDANCE TO THAT ERA, AND SOME MOURN ITS PASSING, BUT REGARDLESS OF YOUR PERSPECTIVE WE WILL NEVER SEE THOSE DAYS AGAIN IN MY OPINION. NOR SHOULD WE WANT TO, BECAUSE THE NEW ERA WITH ITS MARKET RESPONSIVE APPROACH AND RELATIVE LACK OF GOVERNMENT INTERFERENCE MINIMIZES THE CHANCE OF PRICING ABERRATIONS COMPARED TO THE RIGID REGULATED MECHANISM OF GOVERNMENT INTERVENTION.

HOW DID THINGS WORK IN THOSE DAYS? FROM 1975 TO 1985, GAS PRICES WERE SET BY GOVERNMENTS. GENERALLY, PRICES WERE INCREASED AT A CERTAIN RATE BY AGREEMENT, WITHOUT NECESSARILY ANY REFERENCE TO THE REALITIES OF THE MARKETPLACE. AS A RESULT, IN THE EARLY TO MID EIGHTIES, THERE WAS DRASTIC MARKET LOSS IN THE EXPORT MARKET AS PRICES EXCEEDED MARKET REALITIES, AND AS WELL IN THE CANADIAN MARKETS WE WERE AT THE POINT, OR IN SOME CASES HAD PASSED THE POINT, OF SEVERE LOSSES TO COMPETING FUELS AS GAS PRICES OUTSTRIPPED HEAVY FUEL OIL AND OTHER ALTERNATIVES.

DURING THAT PERIOD, THERE WAS ESSENTIALLY ONE SELLER OF GAS TO EASTERN CANADA - TCPL, AND THEY HAD A LOCK ON CANADIAN LDC SUPPLY TO 1995 IN MOST CASES. THE NUMBER OF SHIPPERS ON THE TCPL SYSTEM COULD BE COUNTED ON TWO HANDS. THE LOCAL DISTRIBUTION COMPANIES ("LDC'S") WERE THE SOLE SUPPLIERS OF NATURAL GAS TO THEIR FRANCHISE AREAS, HAVING A MONOPOLY IN BOTH THE SUPPLY OF GAS AND THE TRANSPORTATION WITHIN THE FRANCHISE.

FINALLY, AND AS ALWAYS, MARKET REALITIES BROUGHT A STORM CLOUD TO THIS OTHERWISE PRISTINE SCENARIO. AS I MENTIONED EARLIER, THERE WAS A POTENTIAL FOR LARGE MARKET LOSS TO ALTERNATIVE FUELS. IN ADDITION, AT THE WESTERN END, MANY PRODUCERS OF GAS WERE COMPLETELY UNABLE TO MARKET THEIR PRODUCT, BECAUSE KEY AGGREGATORS SUCH AS TCPL WERE OVER-CONTRACTED. DUE TO TRANSPORTATION RESTRICTIONS, THE TCPL CONTRACTUAL LOCK-UP ON EASTERN MARKETS, AND OTHER FACTORS, THESE SUPPLIERS FACED THE NEXT DECADE OR SO WITH LITTLE HOPE OF MARKETING THEIR PRODUCT, AND IN SOME CASES, OF SURVIVING. SIMILARLY, A NUMBER OF OUR CUSTOMERS WISHED TO CONTRACT DIRECTLY WITH WESTERN SUPPLIERS AS OPPOSED TO BUYING LDC SYSTEM SUPPLY, AND THE REGULATED SCENARIO MADE THIS EXTREMELY DIFFICULT, ALTHOUGH NOT IMPOSSIBLE AS EVIDENCED BY TWO DIRECT PURCHASE ARRANGEMENTS WHICH UNION WAS COMPLETING WITH CUSTOMERS EVEN PRIOR TO THE OCTOBER 31ST NATURAL GAS AGREEMENT. IN SHORT, HOWEVER, MARKET REALITIES AND THE DEMANDS OF BOTH BUYERS AND SELLERS FOR ADDITIONAL FREEDOM AND COMPETITION DEMANDED AN END TO THE REGULATED ERA.

SLIDE 4
KEY EVENTS SINCE DEREGULATION

I WILL NOW OUTLINE SOME OF THE KEY EVENTS THAT HAVE OCCURRED SINCE DEREGULATION, AND THEIR IMPACT ON THE INDUSTRY. THEN I WILL SHOW YOU A FEW SLIDES TO EMPHASIZE THESE POINTS.

THE FIRST AND MOST IMPORTANT EVENT IN THE DEREGULATED ENVIRONMENT WAS OPEN ACCESS TRANSPORTATION ON TCPL FOR END USERS. THIS HAD THE IMPACT OF BRINGING COMPETITION TO TCPL'S SUPPLY. IT ALLOWED AN END USER TO CONTRACT DIRECTLY FOR SUPPLY WITH A PRODUCER FOR A CERTAIN VOLUME, AND RELIEVED TCPL AND THE DISTRIBUTOR OF THAT VOLUME IN THEIR SUPPLY CONTRACTS. THIS RESULTED IN A MASSIVE LOSS IN MARKET SHARE FOR TCPL'S SYSTEM SUPPLIERS AS END USERS RAPIDLY MOVED TO MINIMIZE THEIR ENERGY COSTS. OPEN ACCESS WAS NOT INITIALLY ALLOWED FOR DISTRIBUTORS IN ORDER TO ACCESS CHEAPER GAS SUPPLIES FOR THEIR RESIDENTIAL AND COMMERCIAL CUSTOMERS, A SITUATION WHICH EVENTUALLY LED TO THE SO-CALLED "SELF DISPLACEMENT" ISSUE.

THIS ADVENT OF GAS ON GAS COMPETITION ALSO CAUSED A DRASTIC DROP IN PRICES. THOSE SUPPLIERS WHO HAD BEEN DESPERATE TO MOVE THEIR PRODUCT INTO A PREVIOUSLY LOCKED UP MARKETPLACE WERE WILLING TO TAKE SUBSTANTIAL PRICE CUTS, SOMETIMES BELOW REPLACEMENT COST, IN ORDER TO MOVE THEIR PRODUCT, GAIN CASH FLOW, AND IN SOME CASES KEEP THEIR BANKERS AT BAY.

IMPORTANT ALSO WAS THE RECONTRACTING BETWEEN TRANSCANADA'S MARKETING SUBSIDIARY, WESTERN GAS MARKETING LIMITED, AND THE LDC'S. THESE WERE PROLONGED AND DIFFICULT NEGOTIATIONS, AS THE PARTIES ATTEMPTED TO CHANGE THE WAY BUSINESS HAD BEEN DONE FOR 25 YEARS IN A MANNER WHICH WOULD BE FAIR TO BOTH PRODUCERS AND CONSUMERS. THERE WERE SEVERE RESTRICTIONS PLACED ON BOTH PARTIES, THE LARGEST BEING THAT NEITHER PARTY, FROM A PRACTICAL AND POLITICAL PERSPECTIVE, COULD WALK FROM THE CONTRACTS EVEN HAD THEY WANTED TO. HENCE THE NEGOTIATIONS WERE CONSTRAINED AND DIFFICULT, BUT IN MY VIEW AN ACCEPTABLE BUSINESS COMPROMISE WAS REACHED WHICH FULFILLED THE OBJECTIVE OF FAIR TREATMENT FOR PRODUCERS AND CONSUMERS ALIKE. I CONCEDE IT ISN'T PERFECT, BUT IT IS CERTAINLY AN IMPROVEMENT OVER THE NOW FAMOUS "RUSTY CHAIN SAW OF RE-REGULATION".

DEREGULATION ALSO BROUGHT WITH IT REVIVED EXPORTS, AS EXPORT CONTROLS WERE SLACKENED BY THE FEDERAL GOVERNMENT, AND REVIVED IMPORTS OF AMERICAN GAS TO CANADA.

ALONG WITH THE RELAXATION ON EXPORT REGULATIONS CAME RELAXATION OF THE "SURPLUS TEST" PROTECTION WHICH HAD IN EARLIER DAYS PROVIDED CANADIANS WITH A GUARANTEE OF 25 YEARS OF GAS ON THE SHELF BEFORE SUPPLIES COULD BE EXPORTED. NOW A "MARKET BASED" SURPLUS TEST PROCEDURE REMAINS, USING NOT A FORMALISTIC METHOD BUT RATHER CONSISTING OF NATIONAL ENERGY BOARD MONITORING, AN EXPORT IMPACT ASSESSMENT AT EACH EXPORT HEARING, AND A COMPLAINTS PROCEDURE UNDER WHICH CANADIANS CAN COMPLAIN IF THEY ARE UNABLE TO PURCHASE GAS UNDER THE SAME TERMS AND CONDITIONS AS EXPORT CUSTOMERS. THIS LATTER PROCEDURE HAS NEVER BEEN TESTED.

ALONG ALSO CAME THE FREE TRADE AGREEMENT. THIS HAS LED TO THE DEBATE AS TO WHETHER IT MAY PROHIBIT OR HANDICAP THE NATIONAL ENERGY BOARD IN CARRYING OUT ITS RESPONSIBILITIES UNDER ITS ACT, WHICH ACT REQUIRES IT TO ENSURE THAT THE REASONABLY FORESEEABLE NEEDS OF CANADIANS ARE LOOKED AFTER BEFORE ALLOWING GAS TO BE EXPORTED. THIS IS CURRENTLY A HOT TOPIC WITHIN THE INDUSTRY AND I DO NOT PROPOSE TO COMMENT FURTHER ON IT TODAY.

DEREGULATION ALSO BROUGHT MANY NEW PLAYERS, WITH TCPL MOVING FROM A HANDFUL OF SHIPPERS PRE-DEREGULATION TO NEARLY 1,000. DISTRIBUTORS MOVED FROM DEALING WITH ONE OR TWO GAS SUPPLIERS TO HUNDREDS. ALL THESE NEW PLAYERS HAVE PUT INCREASED DEMANDS ON THE SYSTEM AND THE SYSTEM'S INFRASTRUCTURE, AND STRETCHED IT IN TERMS OF TRANSPORTATION AND STORAGE CAPABILITY.

LASTLY, AND INEVITABLY IN ANY RADICAL NEW DEVELOPMENT SUCH AS DEREGULATION, COMES A LACK OF UNDERSTANDING AND RESULTANT FRICTION BETWEEN OPPOSITE ENDS OF THE INDUSTRY. PROBABLY THE BEST EXAMPLE OF THIS WAS THE SELF DISPLACEMENT ISSUE, WHERE THOSE NOT DEEPLY INVOLVED IN THE ISSUES UNDERSTOOD IT TO BE AN ATTEMPT AT CONTRACT ABROGATION IN THE LONG TERM. IN REALITY, IT WAS A SHORT TERM LEVERAGE TACTIC TO ENSURE ALL CUSTOMERS OF DISTRIBUTORS WERE TREATED FAIRLY. ANOTHER EXAMPLE WOULD BE THE SHRILL CRIES WE OCCASIONALLY HEAR THAT EASTERN DISTRIBUTORS ARE ATTEMPTING TO CONTRACT SHORT TERM ONLY AND SWITCHING FROM LONG TERM FIRM SUPPLY TO SPOT GAS, COMMENTS WHICH CAN ONLY BE MADE BY THOSE NOT IN POSSESSION OF THE FACTS. MORE ON THAT LATER.

THIS IS A LONG TERM INDUSTRY IN WHICH WE SERVE, AND I COMMEND TO YOU ALL EFFORTS TO IMPROVE YOUR LEVEL OF UNDERSTANDING OF YOUR FELLOWS AT OPPOSITE ENDS OF THE PIPE TO ENSURE THIS INDUSTRY SURVIVES AND PROSPERS FOR ALL INVOLVED IN IT.

NOW LET'S LOOK AT A FEW SLIDES WHICH HELP TO DEMONSTRATE SOME OF THE CHANGES I JUST DESCRIBED.

SLIDE 5
DIRECT PURCHASE ACTIVITY

SLIDE 5 SHOWS THE PROGRESS OF DIRECT PURCHASE ACTIVITY IN UNION'S FRANCHISE AREA SINCE THE ADVENT OF DEREGULATION. FROM OUR FIRST TEN BILLION FOOT PER YEAR DIRECT PURCHASE IN APRIL OF 1986, DIRECT PURCHASE ACTIVITY HAS INCREASED TO OVER 128 BILLION CUBIC FEET PER YEAR IN UNION'S FRANCHISE AREA ALONE, REPRESENTING SOME 46% OF OUR TOTAL MARKET. THE NUMBER OF DIRECT PURCHASE CUSTOMERS HAS GONE FROM NIL TO OVER 200. OVERALL, EAST OF MANITOBA, OVER 330 BCF OF LOAD HAS ELECTED DIRECT PURCHASE, OR APPROXIMATELY ONE-THIRD OF THE TOTAL GAS MARKET EAST OF MANITOBA.

UNION VIEWS DIRECT PURCHASE AS HEALTHY AND HAS SUPPORTED THIS ACTIVITY AS EARLY AS THE ONTARIO ENERGY BOARD FEEDSTOCK HEARINGS IN THE VERY EARLY 1980'S. IT IS THIS VEHICLE WHICH ALLOWED OUR CUSTOMERS TO BUY THEIR OWN GAS AT COMPETITIVE PRICES WHEN WE OURSELVES COULD NOT DUE TO THE "LOCK UP" OF THE TCPL CONTRACTS AND THE "NO SELF DISPLACEMENT" RULING OF THE NATIONAL ENERGY BOARD. ABSENT THIS VEHICLE, UNION, AND ALBERTA GAS SUPPLIERS, COULD HAVE LOST UP TO 70 BILLION FEET OF LOAD TO ALTERNATIVE FUELS IN UNION'S AREA ALONE. UNION CONTINUES TO SUPPORT THE DIRECT PURCHASE CONCEPT, ALTHOUGH WE DO HAVE CONCERNS WITH RESPECT TO THE SO-CALLED "CORE MARKET" CUSTOMERS, SOME OF WHOM MAY BE TAKING RISKS THEY ARE NOT AWARE OF WHEN THEY ELECT DIRECT PURCHASE.

NEW DIRECT PURCHASE ACTIVITY IN UNION'S FRANCHISE AREA HAS ESSENTIALLY CEASED BECAUSE THE ONLY TCPL TRANSPORTATION LEFT TO UNION'S AREA IS THE LESS ATTRACTIVE FST TRANSPORTATION, BUT MORE IMPORTANTLY BECAUSE UNION'S WEIGHTED AVERAGE COST OF GAS ("WACOG") HAS DECLINED TO THE EXTENT THAT THOSE WHO HAVE NOT ALREADY ELECTED DIRECT PURCHASE CANNOT ACCESS RELIABLE GAS SUPPLIES AT SIGNIFICANT SAVINGS TO UNION'S SYSTEM SUPPLY.

SLIDE 6
PRE-DEREGULATION GAS PORTFOLIO

JUST AS END USE CUSTOMERS DIVERSIFIED THEIR SUPPLY OPTIONS, SO HAVE DISTRIBUTORS. THIS SLIDE SHOWS UNION'S PORTFOLIO OF SUPPLIES IN 1985, WITH 95% SUPPLIED BY TCPL AND 5% BY PRODUCTION MANUFACTURED OR PRODUCED IN ONTARIO.

SLIDE 7
1990 GAS PORTFOLIO

SLIDE 7 SHOWS OUR FORECAST PORTFOLIO FOR FISCAL '90 (APRIL 1/89 - MARCH 31/90). YOU CAN SEE THAT WGML VOLUMES HAVE DROPPED TO 32%, MOST OF WHICH HAS BEEN REPLACED BY DIRECT PURCHASE GAS, BUT A SIGNIFICANT PORTION OF WHICH HAS BEEN REPLACED BY NEW LONG TERM FIRM SUPPLIES BROUGHT DIRECTLY FROM WESTERN CANADIAN SUPPLIERS SUCH AS SASKOIL, PETRO-CANADA, AND SO ON. THIS SEGMENT OF THE PIE IS INCREASING RAPIDLY, WITH UNION HAVING CONTRACTED FOR ANOTHER 10 BILLION FEET OF SUCH SUPPLY TO BEGIN THIS WINTER AND NEARLY 20 BILLION FEET TO BEGIN AT NOVEMBER 1991. IN THIS WAY IS COMPETITION ENHANCED, OUR PORTFOLIO DIVERSIFIED AND STRENGTHENED, AND ADDITIONAL OPPORTUNITIES FOR SUPPLIERS PRESENTED.

SLIDE 8
HISTORICAL WACOG

THIS IS A VERY INTERESTING SLIDE AND TELLS A KEY STORY. IT SHOWS UNION'S HISTORICAL WEIGHTED AVERAGE COST OF GAS LANDED IN ONTARIO. YOU CAN READILY SEE THE BENEFIT OF DEREGULATION TO CONSUMERS, ALTHOUGH AT GREAT PAIN TO SUPPLIERS.

YOU CAN INSTANTLY APPRECIATE FROM THIS SLIDE THE REASON FOR THE EXTREMELY HIGH DIRECT PURCHASE ACTIVITY. FOR EXAMPLE, IN FISCAL 1986 WHEN OUR WACOG WAS ABOUT $4.00/MCF, WE ESTIMATE A DIRECT PURCHASER COULD HAVE ACCESSED SUPPLY LANDED IN ONTARIO FOR APPROXIMATELY $2.50-2.60/MCF, OR A SAVINGS OF NEARLY 40% OVER DISTRIBUTORS' SUPPLY. HENCE IT IS NOT "DISLOYALTY" OR ANY OTHER DESPICABLE MOTIVE THAT DROVE CUSTOMERS TO DIRECT PURCHASE, BUT SIMPLY THE NORMAL BUSINESS COMMON SENSE WHICH ANY RATIONAL BUSINESSMAN WOULD USE IN SELECTING A SUPPLY OPTION. NOW, WITH THE RAPID DROP IN OUR WACOG, THE SAVINGS TO DIRECT PURCHASERS IS RAPIDLY DIMINISHING AND AS SUPPLY TIGHTENS WE EXPECT DIRECT BUYERS TO BEGIN RETURNING TO THE SYSTEM. NOTE ALSO THAT WE FORECAST RISING AVERAGE PRICES BEGINNING NEXT YEAR.

SLIDE 9
EXPORTS INCREASING

SLIDE 9 SHOWS IN VIVID TERMS THAT EXPORTS HAVE INCREASED RAPIDLY SINCE DEREGULATION, EVEN BEFORE THE LARGE NEW EXPORTS WHICH WILL BEGIN TO FLOW SHORTLY TO THE U.S. NORTHEAST AND TO CALIFORNIA. AS WELL, THE SLIDE ONLY SHOWS EXPORT FLOWS, AND DOES NOT SHOW THE EVEN MORE IMPRESSIVE - OR DISTURBING - PICTURE OF RESERVES DEDICATED TO THE EXPORT MARKET.

SLIDE 10
IMPORT VOLUMES

JUST AS EXPORTS HAVE INCREASED, SO HAVE IMPORTS, AND THEY WILL I THINK CONTINUE TO INCREASE. THE SLIDE SHOWS UNION GAS' IMPORT PATTERN FOR THIS FISCAL YEAR ENDING NEXT APRIL, AND AS WELL THE IMPORTS OF OTHERS. THESE IMPORTS ARE MOVING EXCLUSIVELY THROUGH OUR PANHANDLE IMPORT SYSTEM UNDER THE RIVER AT DETROIT/WINDSOR, AND ARE MAINLY SPOT GAS. WE HAVE NOT PURCHASED THIS VOLUME OF U.S. IMPORT BASED ON PRICE ALONE, BUT BECAUSE THE LACK OF CAPACITY ON THE TRANSCANADA SYSTEM HAS RESTRICTED UNION'S ACCESS TO WESTERN CANADIAN SUPPLIES, OUR PREFERRED SOURCE OF GAS. FOR THAT REASON, UNION, OTHER DISTRIBUTORS, AND FOR THE FIRST TIME IN HISTORY, OUR OWN END USE DIRECT PURCHASE CUSTOMERS, HAVE BEEN IMPORTING RELATIVELY LARGE AMOUNTS OF AMERICAN GAS.

THE RECENTLY APPROVED 24" ST. CLAIR LINE CONNECTING UNION GAS TO MICHCON AND ANR IS NOT LIKELY TO INCREASE THESE VOLUMES IN THE NEAR FUTURE, FOR UNION AT LEAST, BUT RATHER TO CHANGE THEIR CHARACTER FROM SPOT GAS TO LONG TERM FIRM GAS.

I AGAIN EMPHASIZE THAT THIS VOLUME OF U.S. GAS SUPPLY IS NOT NECESSARILY BY CHOICE, BUT RATHER DUE TO THE LACK OF CAPACITY ON THE TRANSCANADA SYSTEM. THIS EXTENSIVE MARKET PENETRATION BY U.S. SUPPLIERS IS A DIRECT RESULT OF THE LACK OF SUFFICIENT ADVANCE CAPABILITY (CAPACITY FOR UNIDENTIFIED BUT PROBABLE LOADS) ON THE TCPL SYSTEM, AN ISSUE WHICH I WILL DISCUSS IN MORE DETAIL LATER.

SLIDE 11
PURCHASING DIVERSITY AND TERM

THIS SLIDE SHOWS UNION'S PORTFOLIO OF SUPPLIES AS AT JULY OF 1989. TWO MESSAGES SHOULD BE APPARENT FROM THIS SLIDE. FIRSTLY, UNION, LIKE ANY PROFESSIONAL PURCHASER OF NATURAL GAS, IS DIVERSIFYING ITS PORTFOLIO AMONGST SUPPLIERS, GEOGRAPHIC BASINS, AND TERM, AND IS DEVELOPING A PORTFOLIO IN THESE RESPECTS. THE SECOND OBVIOUS CONCLUSION SHOULD BE THE HEAVY WEIGHTING TO THE LONG TERM. YOU CAN SEE OUR RECENT TENDERS, SHOWN IN RED, WHERE UNION IS FURTHER EXTENDING ITS GAS SUPPLIES INTO THE LONG TERM. IN OUR VIEW, ANY RATIONAL PURCHASER WHO PROPERLY UNDERSTANDS THE GAS SUPPLY AND CONTRACTING SITUATION WILL NOT RELY HEAVILY ON SHORT TERM SUPPLIES UNLESS HE IS ABSOLUTELY CONFIDENT THAT HIS ALTERNATIVE FUEL SUPPLIES, IF HE HAS ANY, WILL REMAIN COMPETITIVE WITH GAS. IN MY OPINION, THIS IS AN UNLIKELY SCENARIO GIVEN THAT THE MAJOR COMPETING FUEL IN OUR FRANCHISE AREA, HEAVY FUEL OIL, IS WAITING TO REGAIN ITS MARKETS AS GAS SUPPLIES TIGHTEN.

SLIDE 12

TIGHTENING STORAGE AND TRANSPORTATION CAPACITY WAS YET ANOTHER IMPACT OF DEREGULATION. THIS SLIDE SHOWS THE THROUGHPUT CAPABILITY ON UNION'S DAWN-TRAFALGAR SYSTEM, THE MAIN LINE BIG INCH TRANSMISSION SYSTEM OPERATED BY UNION CONNECTING THE GREAT LAKES SYSTEM AT DAWN NEAR SARNIA TO THE TCPL SYSTEM AT TORONTO. YOU CAN READILY SEE THAT THROUGHPUT HAS INCREASED SINCE DEREGULATION BEGAN, FROM ABOUT 1.8 BILLION FOOT PER DAY PEAK DAY SEND-OUT TO A FORECAST LEVEL OF OVER 3-1/2 BCF PER DAY IN THE MID '90'S. STORAGE CONTRACTED OUT TO OTHERS, WHICH IS IN ADDITION TO THE 50-60 BILLION FEET UTILIZED BY UNION FOR ITS OWN CUSTOMERS, HAS INCREASED FROM 30 BILLION FEET TO A FORECAST LEVEL OF SOME 60 BILLION FEET IN THE MID '90'S. MUCH OF THIS IMPACT IS DUE TO THE IMPACT OF DEREGULATION, BUT MORE IMPORTANTLY TO GROWING MARKETS IN EASTERN CANADA AND BEYOND, AND TO INCREASED USE OF STORAGE TO MAXIMIZE PIPELINE EFFICIENCY. INDEED, UNION NOW HANDLES OVER 50% OF THE GAS SOLD EAST OF ALBERTA AND BETWEEN SALES WITHIN OUR FRANCHISE AREA AND OUR TRANSPORTATION AND STORAGE THROUGHPUT, HAS TOTAL THROUGHPUT IN EXCESS OF 500 BILLION FEET PER YEAR.

SLIDE 13
CHANGE IN TERM OF CONTRACT

NOW I HAVE A QUIZ FOR YOU! LET'S LOOK AT THE MAJOR ONTARIO DISTRIBUTORS, UNION GAS, CONSUMERS' GAS, ICG ONTARIO, AND AS WELL AT THE TYPICAL INDUSTRIAL CUSTOMER IN ONTARIO. WOULD THOSE WHO THINK THAT THE LDC'S ARE SIGNING, ON AVERAGE, SHORTER TERM CONTRACTS SINCE DEREGULATION RAISE THEIR HANDS. HOW MANY THINK WE ARE SIGNING LONGER TERM - PLEASE RAISE YOUR HANDS? NOW FOR THE TYPICAL INDUSTRIAL - HOW MANY THINK THEY ARE SIGNING SHORTER TERM CONTRACTS FOR GAS COMPARED TO PRE-DEREGULATION? AND HOW MANY THINK THEY ARE SIGNING LONGER TERM - PLEASE RAISE YOUR HANDS?

OKAY, LET'S LOOK AT SLIDE 13 AND SEE WHAT THE FACTS ARE. ALL THE DISTRIBUTORS MENTIONED HAVE A LONGER TERM PORTFOLIO NOW THAN THEY HAD PRE-DEREGULATION IF YOU COUNT THOSE GAS SUPPLIES FOR WHICH THEY CONTROL THE TERM, OR IN OTHER WORDS, EXCLUDING THE GAS LDC'S PURCHASE FROM BUY/SELL DIRECT PURCHASERS AND EXCLUDING WGML "BLOCK B" VOLUMES. IN THE FORMER CASE, THE LDC'S DO NOT HAVE

THE ABILITY TO IMPOSE ON THESE CUSTOMERS A MINIMUM TERM OF CONTRACT - THE CUSTOMER SETS IT.

IN THE CASE OF BLOCK B VOLUMES, WHICH ARE 2-5 YEAR TERMS, IT IS NOT THAT DISTRIBUTORS PREFERRED SHORT TERM SUPPLY, BUT RATHER BECAUSE WGML COULD NOT OR WOULD NOT PROVIDE ANY SECURITY OF SUPPLY FOR THESE BLOCK B VOLUMES OTHER THAN GUARANTEEING TO INTERRUPT INTERRUPTIBLE SUPPLIES PRIOR TO INTERRUPTING THESE VOLUMES. GIVEN THAT THIS IS AN INTEGRAL PART OF OUR GAS SUPPLY AND NOT TARGETED TO ANY PARTICULAR MARKET, DISTRIBUTORS GENERALLY COULD NOT ACCEPT SIGNING LONG TERM FOR THIS DEGREE OF RELIABILITY GIVEN THE TIGHTENING GAS SUPPLY SITUATION. THIS IS NOT A CRITICISM OF WGML. I UNDERSTAND WGML PREFER THIS ARRANGEMENT TO MAINTAIN A STRATEGY OF BEING ABLE TO SWING THE SUPPLY BLOCK INTO THE EXPORT MARKET AS CONDITIONS IMPROVE. HOWEVER, THE DISTRIBUTOR'S CURRENT TERM OF CONTRACT WOULD BE MUCH LONGER HAD WE BEEN ABLE TO CONTRACT FOR LONG TERM SECURE SUPPLY UNDER APPROPRIATE TERMS AND CONDITIONS. SO I EXCLUDE BLOCK B IN OUR CALCULATION.

THE SLIDE SHOWS FOR THE SUPPLIES LDC'S CONTROL, EASTERN LDC'S CLEARLY HAVE MOVED TO LONGER TERM CONTRACTING. WE DO THIS BECAUSE WE ARE IN THE LONG TERM BUSINESS AND WE APPRECIATE THAT SECURE LONG TERM CONTRACTS UNDERPIN OUR FACILITIES AND OUR ABILITY TO SUPPLY OUR CUSTOMERS.

KEEP IN MIND THAT THE SLIDE SHOWS THE WEIGHTED AVERAGE OF CONTRACTS, NOT INDIVIDUAL CONTRACTS. OUR RECENT TENDER FOR GAS SUPPLY FOR NOVEMBER '91 INCLUDES CONTRACTS WITH TERMS OF 16 AND 20 YEARS. HENCE, OUR NEW CONTRACTS THIS WINTER TEND TO BE MORE THAN DOUBLE THE LENGTH OF THE AVERAGE TERM PRE-DEREGULATION.

THE MARKED DIFFERENCE BETWEEN PERCENTAGE INCREASES FOR THE VARIOUS LDC'S IS MORE DRAMATIC THAN IT SEEMS. BECAUSE UNION HAS MORE "MIDDLE FILL" IN OUR PORTFOLIO, THE CHANGE IN OUR AVERAGE WEIGHTED CONTRACT LENGTH IS LESS THAN THAT OF OTHER DISTRIBUTORS. AS WELL, THE INCREASES OF ICG AND CONSUMERS' ARE HEAVILY WEIGHTED BY THE LARGE PERCENTAGE OF WGML BLOCK A GAS IN THEIR PORTFOLIO, AND THE FACT THAT THIS GAS HAS BEEN TERMED OUT TO 15 YEARS. IT SHOULD ALSO BE APPRECIATED THAT THE WEIGHTED AVERAGE INCREASES SLOWLY, EVEN THOUGH, FOR EXAMPLE, UNION IS TENDERING FOR GAS SUPPLIES NOW IN THE 16-20 YEAR RANGE.

AS FOR THE TYPICAL INDUSTRIAL, HIS PRACTICE HASN'T CHANGED IN THE SENSE OF TERM OF CONTRACT. PRIOR TO DEREGULATION HE SELDOM SIGNED FOR MORE THAN ONE YEAR, AND THE SAME IS TRUE TODAY. HE DOES NOT RISK SIGNING LONG TERM FOR GAS ANY MORE THAN FOR OTHER COMMODITIES HE PURCHASES. WHAT HAS CHANGED IS FROM WHOM HE BUYS THE GAS. HE USED TO BUY FROM THE DISTRIBUTOR, WHO SOLD ONE YEAR TO THE INDUSTRIAL AND CONTRACTED 15 YEARS. NOW THE INDUSTRIAL BUYS DIRECTLY FROM THE SUPPLIER AND STILL SIGNS A ONE YEAR CONTRACT. SO WHAT HAS CHANGED, CONTRARY TO COMPLAINTS ABOUT THE EAST MOVING TO SHORTER TERM CONTRACTING PRACTICES, IS NOT THE TERM OF THE INDUSTRIAL'S CONTRACT. RATHER, IT'S A PERCEPTION CHANGE BECAUSE THE CURRENT SUPPLIER DID NOT PREVIOUSLY APPRECIATE THAT THAT INDUSTRIAL CUSTOMER ALWAYS BOUGHT ONE YEAR.

SO PLEASE DON'T REPEAT THE OFT QUOTED PIECE OF MIS-INFORMATION THAT EASTERNERS HAVE MOVED TO SHORT TERM CONTRACTING BECAUSE AS THE SLIDE DEMONSTRATES THE REVERSE IS TRUE. AND SECONDLY, PLEASE DON'T TRY TO FORCE THE INDUSTRIAL TO GO LONG TERM BECAUSE HIS HEAVY FUEL OIL SUPPLIER DOESN'T. I WOULD HAZARD A GUESS THAT IF WE TRIED TO FORCE INDUSTRIAL CUSTOMERS TO START CONTRACTING 10 YEAR TERMS TOMORROW, ALBERTA SUPPLIERS COULD LOSE 70 BILLION FEET OF ANNUALIZED

LOAD BY THE END OF THE YEAR IN UNION'S AREA ALONE, AS THAT LOAD SWITCHED TO THE MANY HIGHLY COMPETITIVE ALTERNATIVE FUELS.

THE NEXT DECADE

I HAVE SPENT SOME TIME ON THE PAST BECAUSE AS ALWAYS IT IS PROLOGUE TO THE FUTURE AND ESSENTIAL TO UNDERSTANDING THE ISSUES WE WILL ADDRESS OVER THE NEXT DECADE. NOW SOME PREDICTIONS FOR THE NEXT DECADE:

SLIDE 14
TIGHT SUPPLY

MY FIRST PREDICTION IS THAT SUPPLY WILL TIGHTEN ESPECIALLY IN THE NEXT ONE TO FOUR YEARS. THIS SLIDE SHOWS THE SITUATION IN THE UNITED STATES OVER THE LAST NUMBER OF YEARS WITH A PROJECTION OUT TO 1990. YOU DON'T HAVE TO BE A ROCKET SCIENTIST TO SEE WHAT THAT IS TELLING YOU, TAKEN IN COMBINATION WITH **SLIDE 15**. AS WELL, THE QUALITY OF MANY OF THE RESERVE ADDITIONS ARE SUSPECT GIVEN THAT SOME ARE REALLY NOT DUE TO ADDITIONAL DRILLING, BUT SIMPLY "PAPER ADDITIONS" RESULTING FROM REVISIONS AND EXTENSIONS TO EXISTING DATA.

SLIDE 16

SLIDE 16 SHOWS A SIMILAR PICTURE FOR CANADA. AGAIN PLEASE NOTE THE DRAMATIC DIFFERENCE BETWEEN TOTAL RESERVE ADDITIONS AND THOSE DUE TO ACTUAL DISCOVERIES AS OPPOSED TO REVISIONS AND EXTENSIONS. THIS REPRESENTS A VERY BLEAK PICTURE AND YOU WOULD SEE A SIMILAR PATTERN IN RIG COUNT AS TO THE UNITED STATES.

NEVERTHELESS, SAY SOME, THERE IS STILL LOTS OF GAS OUT THERE. THAT'S TRUE, BUT AS **SLIDE 17** SHOWS THERE IS VERY LITTLE UNCONTRACTED GAS. THE VAST MAJORITY OF THE RESERVES ARE DEDICATED LONG TERM TO SPECIFIC AGGREGATORS AND MARKETS AND NOT AVAILABLE TO YOU OR I TO CONTRACT. THESE ARE DECEMBER 1987 DATA BUT MORE RECENT STUDIES GIVE NEARLY THE SAME NUMBERS.

NOW DON'T RUSH OUT AND PANIC AND SWITCH TO ANOTHER FUEL. THERE IS LOTS OF GAS OUT THERE, AND A LOT OF GAS POTENTIAL, BUT IT TAKES TIME, MONEY, AND RISK TAKERS TO DEVELOP - A DECADE TO BRING A FIELD LIKE CAROLINE INTO PLAY, PARTICULARLY GIVEN REGULATORY CONSTRAINTS. BUT THE NET RESULT IS THAT SUPPLY IS GOING TO TIGHTEN, PARTICULARLY IN THE NEXT ONE TO FOUR YEARS BEFORE THE NECESSARY HIGHER PRICES WILL BRING NEW SUPPLIES ON. THE NEW EXPORTS WHICH WILL FLOW TO CALIFORNIA AND THE U.S. NORTHEAST WILL EXACERBATE THE SITUATION. THIS IS A GOOD SITUATION FOR "SYSTEM" PRODUCERS WHO HAVE ENDURED YEARS OF PAIN SINCE DEREGULATION, BUT WILL CAUSE REAL PROBLEMS FOR CONSUMERS WHO DO NOT PLAN AND CONTRACT ADEQUATELY.

ARE HIGHER PRICES BAD? NOT AT ALL, PROVIDING THEY DO NOT INCREASE TOO FAR AND TOO FAST TO THE EXTENT OF MARKET LOSS TO ALTERNATIVE FUELS. INDEED, PRICES OVER THE LAST SEVERAL YEARS HAVE BEEN AT A LEVEL WHICH IS UNCOMFORTABLY LOW FROM THE PERSPECTIVE OF ENSURING SUPPLY AVAILABILITY. ARE YOU SURPRISED TO HEAR THIS FROM AN EASTERN DISTRIBUTOR? WELL YOU SHOULDN'T BE, BECAUSE LIKE YOURSELVES WE ARE IN THE BUSINESS LONG TERM, AND WE UNDERSTAND THAT PRICES THAT ARE TOO LOW OR TOO HIGH WILL DRIVE THE SYSTEM OUT OF BALANCE, AND RESULT EITHER IN INADEQUATE SUPPLIES IN THE FIRST CASE, OR MASSIVE MARKET LOSS IN THE SECOND. OUR OWN REGULATOR, THE ONTARIO ENERGY BOARD, HAS I BELIEVE ACCEPTED

ONTARIO DISTRIBUTORS' POSITION THAT WE SHOULD NOT BE PURSUING "THE LOWEST PRICE", BUT RATHER THE "LOWEST PRACTICAL PRICE", WHICH MEANS THAT PRICE WHICH WILL ENSURE BOTH SHORT AND LONG TERM SECURITY OF SUPPLY AND AVAILABILITY OF ADEQUATE SUPPLIES.

I PREDICT A HARD LANDING FOR SOME DIRECT BUYERS. ALREADY SOME OF THESE COMPANIES HAVE COME TO US EXPRESSING SURPRISE THAT THOSE SUPPLIERS WHO FOUGHT TO SUPPLY THEM GAS OVER THE PAST NUMBER OF YEARS ARE NO LONGER INTERESTED IN BIDDING. NO, I DID NOT SAY THEY WANTED A HIGHER PRICE. THEY DON'T WANT TO SUPPLY AT ALL! THE REASON IS THAT THEY NOW HAVE THE ABILITY AND WOULD RATHER DEDICATE THEIR SUPPLY TO A LONG TERM FIRM MARKET SUCH AS THAT PROVIDED BY EXPORTS OR BY CANADIAN DISTRIBUTORS, RATHER THAN DEDICATE IT TO THE SHORT TERM CUT PRICE MARKET REPRESENTED, IN GENERAL, BY INDUSTRIAL DIRECT PURCHASE.

A SECOND SHOCK FOR SOME OF THESE BUYERS WILL BE THAT THE DISTRIBUTOR CANNOT SUPPLY THEM EITHER IN THE SHORT TERM. THE ONTARIO ENERGY BOARD HAS ALREADY RULED THAT THOSE WHO ELECT DIRECT PURCHASE ARE RESPONSIBLE FOR THEIR OWN SECURITY OF SUPPLY, AND AS A RESULT DISTRIBUTORS ARE NOT COMPELLED TO SERVE THESE CUSTOMERS. OBVIOUSLY WE WANT TO SUPPLY ANY CUSTOMERS SO AS TO KEEP THEM ON GAS AND KEEP THE OVERALL INDUSTRY PIPELINE INFRASTRUCTURE FULL, BUT THOSE WHO APPROACH US ON SHORT NOTICE MAY WELL FIND WE ARE INCAPABLE OF SUPPLYING THEM.

WHEREAS FOUR YEARS AGO WE COULD LINE UP INCREMENTAL GAS SUPPLIES IN AS LITTLE AS SIX MONTHS, THE TIME FRAME HAS NOW EXTENDED TO NEARLY A YEAR, AND I SHORTLY EXPECT TO SEE UP TO THREE YEARS REQUIRED TO LINE UP INCREMENTAL SUPPLY. HENCE THE BEST WE MAY BE ABLE TO DO, PARTICULARLY IF THESE RETURNING BUYERS ARE LARGE, IS SERVE THEM ON A REASONABLE EFFORTS FULLY INTERRUPTIBLE BASIS FOR THE FIRST SEVERAL YEARS.

I ALSO FORECAST THAT U.S. SUPPLIER PENETRATION OF EASTERN CANADIAN GAS MARKETS WILL CONTINUE. THIS IS NOT BECAUSE EASTERN LDC'S HAVE A PREFERENCE FOR U.S. GAS. IN UNION'S CASE, OUR CLEAR PREFERENCE IS FOR NATIVE CANADIAN SUPPLIES FOR MOST OF OUR SUPPLY. HOWEVER, FOR A NUMBER OF YEARS TCPL COULD NOT OR WOULD NOT BUILD ADVANCE CAPABILITY, OR IF YOU PREFER "DESIGN SPARE CAPACITY WHICH ONE EXPECTS TO HAVE CONTRACTED BY START-UP TIME". NOW, WITH APPLICATIONS FOR TRANSPORTATION SERVICE OUTWEIGHING TCPL'S CAPABILITY TO BUILD, IT MAY BE IMPOSSIBLE TO BUILD ADVANCE CAPABILITY. THE SIMPLE RESULT IS THAT, TODAY, WITH GROWING EASTERN CANADIAN MARKETS, NEW DEMANDS CAN ONLY BE SERVED BY U.S. GAS AND THIS SITUATION MAY PERSIST FOR SEVERAL YEARS. GIVEN THE DRIVE BY EASTERN CANADIAN BUYERS FOR SECURITY OF SUPPLY, I WOULD EXPECT THAT THE CURRENT LARGE VOLUME OF U.S. SPOT IMPORTS WOULD BE REPLACED BY LONG TERM FIRM U.S. SUPPLIES. AN EXAMPLE IS UNION'S RECENT ARRANGEMENT WITH SHELL TRADING. THESE SUPPLIES ARE AVAILABLE FROM A NUMBER OF MAJOR INTEGRATED U.S. SUPPLIERS WHO DO HAVE RESERVES TO PRODUCTION RATIOS FAR IN EXCESS OF THE UNITED STATES IN GENERAL, AND FURTHERMORE, NEARLY 50% OF U.S. GAS SUPPLIES ARE UNCONTRACTED VS. PERHAPS 12-20% IN ALBERTA.

I PREDICT THE CORE MARKET ISSUE WILL DIE A NATURAL DEATH. GIVEN THE TIGHTENING SUPPLY AND RISING PRICES, AND THE REDUCTION IN DISTRIBUTORS' AVERAGE COST OF GAS, THE DRIVING FORCE FOR ANY DIRECT PURCHASERS, LET ALONE CORE MARKET WILL DIMINISH AND CORE MARKET DIRECT PURCHASE ACTIVITY WILL CEASE.

I WOULD PREDICT THAT LNG IMPORTS WILL PLAY AN INCREASING ROLE IN THE UNITED STATES AS SHOWN ON **SLIDE 18**. FURTHERMORE, I THINK YOU WILL SEE THE FIRST PROJECT TO IMPORT LNG INTO CANADA WITHIN THE NEXT DECADE.

I SUGGEST THAT ENVIRONMENTAL ISSUES IN NORTH AMERICA WILL ENHANCE NATURAL GAS MARKETS OVER THE NEXT DECADE.

LASTLY, I PREDICT YOU WILL SEE A REBIRTH OF RECOGNITION OF THE VALUE OF THE ONTARIO MARKETPLACE FOR WESTERN CANADIAN SUPPLIERS IN THE VERY NEAR FUTURE. SOME SUPPLIERS BECAME DISENCHANTED WITH THE ONTARIO MARKETPLACE WHEN THEY SAW THEIR MARKETING AGENT, WESTERN GAS MARKETING LIMITED, LOSE MASSIVE AMOUNTS OF THE ONTARIO/QUEBEC MARKET. THIS WAS INTERPRETED AS MARKETPLACE UNRELIABILITY, WHEREAS THE FACTS WERE THAT IT WAS A SIMPLE, BUSINESSLIKE REACTION BY OUR CUSTOMERS TO GAS SUPPLIES WHICH WERE CLEARLY PRICED SIGNIFICANTLY ABOVE THE MARKET. THIS IS READILY RECOGNIZED FROM THE HISTORY OF UNION'S WACOG WHICH I SHOWED YOU EARLIER. THOSE OTHER SUPPLIERS WHO HAVE MOVED INTO OUR MARKETPLACE AND ARE NOW SUPPLYING UNION WITH MARKET SENSITIVE PRICE GAS HAVE ENJOYED 100% ANNUAL LOAD FACTORS WITH NEGLIGIBLE DISPLACEMENT FOR DIRECT PURCHASE, AS DIRECT PURCHASE ACTIVITIES IN OUR FRANCHISE AREA HAVE BASICALLY CEASED.

SLIDE 19
ONTARIO - A VALUED MARKET

WHY SHOULD YOU AS A SUPPLIER SEE ONTARIO AS A VALUED MARKET? THIS SLIDE SHOWS IT. LOOKING AT THE STYLE OF GROWTH IN U.S. MARKETS, IT IS OFTEN CHARACTERIZED BY LARGE CONTROVERSIAL PROJECTS AS OPPOSED TO THE GROWTH IN ONTARIO WHICH TENDS TO BE STEADY INCREMENTAL GROWTH IN THE NORMAL COURSE OF BUSINESS. FOUR OR FIVE PERCENT GROWTH A YEAR DOESN'T SOUND VERY EXCITING, BUT WHEN IT IS ON A MARKET BASE OF ROUGHLY 900 BILLION FEET, THAT GROWTH IS EQUIVALENT TO ONE IROQUOIS SIZE PROJECT EVERY 4.4 YEARS. THIS IS INCREMENTAL GROWTH, BUT THERE ARE ALSO VERY LARGE REPLACEMENT VOLUMES COMING DUE EACH YEAR. IF ONE CONSIDERS THE BLOCK B VOLUMES OF QUEBEC AND ONTARIO DISTRIBUTORS WHICH EXPIRE BETWEEN NOVEMBER 1990 AND NOVEMBER 1992, DIRECT SALES WHICH ARE COMING UP FOR RENEWAL EVERY MONTH TOTALLING SOME 330 BCF PER YEAR EAST OF ALBERTA, AND FIRMING UP SPOT SUPPLIES, WE ESTIMATE OVER 550 BILLION FEET OF ONTARIO AND QUEBEC GAS SUPPLY EXPIRES OVER THE NEXT FIVE YEARS AND CAN BE CAPTURED BY NEW SUPPLIERS. THIS REPRESENTS A TREMENDOUS MARKET OPPORTUNITY FOR YOU AS AN INDIVIDUAL PRODUCER, AND THE INCREMENTAL GROWTH IS A REAL OPPORTUNITY FOR ALBERTA AND SASKATCHEWAN.

THOSE OF YOU FAMILIAR WITH IROQUOIS AND CHAMPLAIN WILL READILY RECOGNIZE THE SECOND ROW ON THIS SLIDE - THE REGULATORY APPROVAL PROCESS AND THE LENGTH OF IT FOR LARGE NEW U.S. PROJECTS. THREE TO TEN YEARS IS A TYPICAL TIME FRAME TO BRING SUCH PROJECTS ON WHEREAS MOVING INCREMENTAL OR REPLACEMENT GAS SUPPLIES TO ONTARIO IS TYPICAL SIX MONTHS FOR SMALL VOLUMES AND A MAXIMUM OF THREE YEARS THESE DAYS FOR LARGE VOLUMES WHERE TCPL CAPACITY MUST BE BUILT. SOME ALBERTA SUPPLIERS HAVE AVOIDED EVEN THIS RELATIVELY SHORT BOTTLENECK BY HAVING THEIR AMERICAN AFFILIATE SUPPLY THE GAS TO UNION THROUGH THE PANHANDLE SYSTEM INITIALLY.

LOAD FACTORS IN ONTARIO MARKETS ARE SUPERIOR TO EXPORT PROJECTS ALMOST WITHOUT EXCEPTION. NEWER PROJECTS INTO THE U.S., PARTICULARLY THE NORTHEAST, EXPECT TO HAVE LOAD FACTORS AS DOES THE BOUNDARY PROJECT, WELL OVER 90%, BUT THIS REMAINS TO BE SEEN. ONTARIO'S PERFORMANCE APPROACHES 100% ON A VOLUME

WEIGHTED AVERAGE, WITH ICG ONTARIO IMPROVING ITS LOAD FACTOR RAPIDLY THROUGH ADDITIONAL USE OF STORAGE.

LET'S TALK ABOUT CONTRACTUAL ASSURANCE OF TAKES. UNION GUARANTEES NOT TO REFUSE YOUR GAS IN ORDER TO PURCHASE ANY LOWER PRICE GAS ELSEWHERE, I.E. NOT TO "SELF DISPLACE". THIS IS ONLY FAIR SINCE WE DON'T ALLOW YOU TO SELL THE GAS YOU HAVE DEDICATED TO US ELSEWHERE ON ANY DAY YOU CAN GET A BETTER PRICE ELSEWHERE. THEREFORE YOUR ONLY OPERATION BELOW 100% LOAD FACTOR, EXCEPTING FORCE MAJEURE, IS TO THE EXTENT YOU LOSE LOAD PRO RATA IF OUR END USE CUSTOMERS ELECT DIRECT PURCHASE. THE SLIDE I SHOWED YOU EARLIER, INDICATING THAT INCREMENTAL DIRECT PURCHASE ACTIVITIES HAVE BASICALLY CEASED IN UNION'S AREA, SHOULD CONVINCE YOU YOUR RISK HERE IS NEGLIGIBLE. YOUR ONLY OTHER RISK IS A MASSIVE MARKET LOSS AS HAS OCCURRED ONLY ONCE IN OUR 75 YEAR HISTORY, IN WHICH CASE YOU COULD ALSO BE TEMPORARILY DISPLACED PRO RATA. HISTORICAL PERFORMANCE SUGGESTS THIS RISK IS NEGLIGIBLE.

HOWEVER, MANY AMERICAN CUSTOMERS ACCUSTOMED TO FERC 380 WILL NOT SIGN NEW CONTRACTS WHICH PROHIBIT SELF DISPLACEMENT, ALTHOUGH THERE ARE SOME EXCEPTIONS SUCH AS THE SHELL/CETI CONTRACT. FOR EXAMPLE, THE IROQUOIS A.N.E. CONTRACTS TO THE U.S. NORTHEAST, AS FILED AT THE NATIONAL ENERGY BOARD, CONTAIN NO CONTRACTUAL ASSURANCES OF TAKES WHATSOEVER. THEY DO PERMIT THE SUPPLIER TO CUT HIS SUPPLY OBLIGATIONS IF THE BUYER IS BELOW 60% OF THE DCQ FOR A YEAR, BUT THIS IS CLOSING THE DOOR LONG AFTER THE HORSE IS OUT OF THE BARN. IF TAKES ARE BELOW THE HIGH LEVELS FORECAST, IT COULD MEAN THAT EXPENSIVE PIPELINE HAS BEEN BUILT WITHOUT GAS BEING TAKEN. THEREFORE, IN EXPORT ARRANGEMENTS SUCH AS THIS, YOU ARE AT RISK ON BOTH SELF DISPLACEMENT OR IF BUYERS' CUSTOMERS ELECT DIRECT PURCHASE.

PLEASE DO NOT TAKE THIS AS A BLANKET CRITICISM OF IROQUOIS - IT IS SIMPLY AN OBSERVATION ON RELATIVE ASSURANCE OF TAKES.

I THINK THE REST OF THE OBSERVATIONS ON THE SLIDE ARE OBVIOUS WITH THE EXCEPTION OF REGULATORY RISK AND TOLLS. MUCH HAS BEEN MADE OF THE TO-DO AT THE ONTARIO ENERGY BOARD HEARINGS ON THE WGML/DISTRIBUTOR DEALS LAST SPRING. THIS DOES NOT SUGGEST THAT YOU ARE AT REGULATORY RISK IN SELLING GAS INTO ONTARIO IN A NORMAL FREELY NEGOTIATED ARRANGEMENT. THE HOOPLA IN THE LAST SEVERAL YEARS WAS WITH RESPECT ONLY TO THOSE PARTICULAR WGML/DISTRIBUTOR DEALS WHICH BY ANY STRETCH OF THE IMAGINATION WERE NOT FREELY NEGOTIATED. HEAVY RESTRICTIONS WERE PLACED ON BOTH PARTIES AT THE TABLE, WITH A RESULTANT COMPROMISE DEAL. DESPITE HEAVY ATTACK BY CERTAIN INTERVENORS, THE ONTARIO ENERGY BOARD APPROVED THE LONG TERM DEALS IN A DECISION NOTED FOR ITS CONCILIATORY TONE. WE HAVE NEVER HAD SUCH CONCERNS EXPRESSED BY THE BOARD ABOUT THE MARKET SENSITIVE DEALS WE ARE DOING WITH COMPANIES SUCH AS PETRO-CANADA AND SASKOIL IN THE NEW ERA OF GAS PURCHASING.

WITH RESPECT TO TOLLS, WE CONTINUE TO HEAR WESTERN PRODUCING ASSOCIATIONS TALKING ABOUT THE IMPACT OF TCPL TOLL INCREASES ON THE PRODUCER. I THINK THE POINT IS MISSED HERE THAT THE VAST MAJORITY OF EXPORT CONTRACTS TO THE U.S. ARE BASED ON A BURNER-TIP NETBACK, SUCH THAT TCPL TOLLS ARE NETTED OFF THE BURNER-TIP PRICE AND THE PRODUCER EATS ANY TOLL INCREASE. HOWEVER, THE REVERSE PRACTICE IS TRUE WITH MOST MARKET SENSITIVE LDC CONTRACTS TO EASTERN CANADA, WITH THE PRICE BEING BOTH SET AND ARBITRATED AT THE ALBERTA BORDER, WITHOUT REFERENCE TO BURNER-TIP PRICING. HENCE ANY TOLL INCREASE ROLLS FORWARD TO THE EASTERN DISTRIBUTOR'S CUSTOMERS, EXCEPT IN THE CASE WHERE THE TOLLS WOULD BE SO HIGH THAT MARKET LOSS BEGINS. IN THAT CASE THE PRODUCER

MUST MAKE A DECISION BETWEEN PRICE AND MARKET SHARE. SO, IN MY VIEW, THE TOLL STRUCTURE TO ONTARIO LDC'S IS ANOTHER REASON MAKING ONTARIO A VERY ATTRACTIVE MARKETPLACE.

SLIDE 20
RECOMMENDATIONS FOR BUYERS

IN CLOSING, I WOULD LIKE TO PROVIDE SOME RECOMMENDATIONS TO THOSE OF YOU IN THE AUDIENCE WHO ARE BUYERS. FIRSTLY, YOU SHOULD PLAN FOR TIGHTENING SUPPLY AND PRICE AND LEARN THE FACTS. DON'T BE LULLED INTO A SENSE OF SECURITY BY HEARING THERE IS LOTS OF GAS OUT THERE. SURE THERE IS - BUT VERY LITTLE UNCONTRACTED AND WHAT THERE IS, IS HEADING SOUTH AT A CONSIDERABLE RATE. UNLESS YOU HAVE CONTRACTED WITH THEM LONG TERM, YOUR SUPPLIER HAS NO OBLIGATION TO SUPPLY BEYOND THE END OF THIS CONTRACT. DON'T BE SURPRISED IF HE PULLS OUT TO MOVE THAT SUPPLY ELSEWHERE. DEVELOP A PORTFOLIO BOTH IN TERMS OF SUPPLIER, TERM, AND SO ON. PLAN FOR AND PROTECT YOURSELF FOR THE LONG TERM.

THOSE WHO DO NOT WISH TO LEARN THE GAS BUSINESS OR ARE NOT STAFFED TO DO SO MAY WISH TO RETURN TO GAS SERVICE WITH THEIR LDC. HOWEVER, YOU MUST RECOGNIZE THAT, IF YOU ARE A SUBSTANTIAL LOAD, IT MAY GENERALLY TAKE A MINIMUM OF ONE YEAR AND UP TO THREE YEARS IN THESE TIGHTENING TIMES FOR THE DISTRIBUTOR TO RESUME SUPPLY TO YOU. THEREFORE YOUR OWN ARRANGEMENTS MUST PROVIDE A BRIDGE PERIOD TO COVER YOU FROM THE TIME YOU REQUEST SERVICE OF YOUR DISTRIBUTOR TO THE TIME IN WHICH HE CAN PROVIDE IT. SMALLER LOADS CAN SOMETIMES BE ACCOMMODATED FASTER, BUT DON'T COUNT ON IT WITHOUT CONSULTATION WITH YOUR LDC.

LASTLY, FOR BUYERS, CONTRACTUAL TERMS DEMANDED BY SELLERS IN THIS TIGHTENING MARKET ARE BECOMING TOUGHER. IT IS BECOMING A SELLER'S MARKET. BE PARTICULARLY CAREFUL OF A NEW PANACEA IN THE MARKETPLACE - THE RESERVATION CHARGE. USED IN PROPER CIRCUMSTANCES SUCH AS THE "GIC" OR GAS INVENTORY CHARGE IN THE UNITED STATES, THIS CAN BE AN ATTRACTIVE FEATURE FOR BOTH BUYER AND SELLER. IN THE UNITED STATES, YOU PAY A RESERVATION CHARGE BUT ARE ALLOWED TO SELF DISPLACE IN RETURN. SOME SELLERS IN CANADA ARE ATTEMPTING TO HAVE YOU SIGN A RESERVATION CHARGE AND YET PROHIBIT SELF DISPLACEMENT. THE NET RESULT IS YOU GET NO BENEFIT OR FLEXIBILITY FROM THE RESERVATION CHARGE, BUT IN THE FEW CASES WHERE YOU HAVE TO REFUSE GAS FOR REASONS COMPLETELY BEYOND YOUR CONTROL, YOU WILL THEN PROBABLY INCUR A NOVA DEMAND CHARGE PENALTY, A TRANSCANADA DEMAND CHARGE PENALTY, LOST SALES MARGIN IF YOU ARE AN LDC, AND TO FINALLY DRIVE THE STAKE COMPLETELY THROUGH YOUR HEART, A RESERVATION CHARGE. COMPARE THIS TO YOUR SUPPLIER'S EXPOSURE WHICH IS GENERALLY A TIME VALUE OF MONEY EFFECT VERSUS YOUR CASH LOSS.

IN OUR VIEW THIS IS AN UNREASONABLE APPROACH. READ UP ON "GIC'S" IN THE UNITED STATES, UNDERSTAND WHERE, WHY, AND HOW THEY ARE USED, AND TAILOR YOUR CONTRACTING PRACTICES ACCORDINGLY.

SLIDE 21
RECOMMENDATIONS FOR SUPPLIER

FIRSTLY, FOR SUPPLIERS, I RECOMMEND YOU PERSONALLY GET TO LEARN YOUR MARKETPLACES. DID YOU KNOW THAT MANY MAJOR NEW EXPORT CONTRACTS HAVE NO CONTRACTUAL GUARANTEES OF TAKES WHEREAS THOSE TO ONTARIO LDC'S DO? DID YOU KNOW THAT MARKET GROWTH EAST OF MANITOBA REPRESENTS ONE IROQUOIS PROJECT EVERY 4.4 YEARS

WITH FAR LESS HASSLE AND RISK? DID YOU KNOW THAT THE "UNRELIABLE" ONTARIO MARKET IS IN FACT PERFECTLY RELIABLE TO NEW MARKET SENSITIVE SUPPLIERS? EVEN IF YOU RELY ON OTHERS TO DO YOUR MARKETING, MAKE SURE YOU YOURSELF KNOW THE MARKET, AND AGREE WITH ALL THE POSITIONS OF THE MARKETER.

RECOGNIZE THE VULNERABILITIES OF EXPORT PROJECTS. MANY OF THESE PROVIDE VERY GOOD OPPORTUNITIES TO PRODUCERS WITH HIGH LOAD FACTORS AND GOOD NETBACKS, BUT OTHERS MAY NOT. THIS COMMENT IS NOT A CRITICISM OF EXPORT PROJECTS, BUT RATHER A PLEA TO RECOGNIZE AND COMPARE THE PROS AND CONS OF EXPORT AND DOMESTIC PROJECTS BEFORE YOU PUT YOUR FOOT COMPLETELY IN ONE CAMP.

DON'T TAKE THE ONTARIO MARKETPLACE AS CAPTIVE. AS I INDICATED, SOME 550 BILLION FEET OF THE 900+ BILLION FOOT MARKET COME UP FOR GRABS OVER THE NEXT FIVE YEARS. YOU COULD LOSE SIGNIFICANT MARKETPLACE TO COMPETING CANADIAN SUPPLIERS OR TO THE CONTINUALLY INCREASING AMERICAN PENETRATION. ALTERNATIVELY, IF YOU GET TO KNOW YOUR MARKETPLACE AND EXPLOIT IT, YOU COULD EXPERIENCE VERY SIGNIFICANT HIGH NETBACK HIGH LOAD FACTOR GAINS AS A SUPPLIER INTO THIS MARKETPLACE. AS WELL, AND BECAUSE YOUR ONTARIO DISTRIBUTORS PLACE SUCH HIGH VALUE ON LONG TERM SECURE SUPPLY, I STRONGLY SUGGEST YOU EXPLOIT THE ATTRACTIVE ONTARIO LDC MARKET.

I WOULD ALSO SUGGEST YOU PUSH YOUR PRODUCER ORGANIZATIONS TO LOBBY FOR SOME ADVANCE CAPABILITY ON THE TCPL SYSTEM IN ORDER TO HOLD AND INCREASE YOUR MARKET. LACK OF ADVANCE CAPABILITY HAS LEFT TCPL INCAPABLE OF SERVING THE EASTERN MARKET GROWTH, AND HAS DIRECTLY RESULTED IN SIGNIFICANT AMERICAN PENETRATION OF THAT MARKETPLACE. ONE OF THE REASONS FOR THIS RAPIDLY INCREASING PENETRATION IS THAT THE AMERICANS THEMSELVES RECOGNIZE THE INHERENT ATTRACTIVENESS OF THE ONTARIO MARKET. SHOCK QUICKLY GIVES WAY TO DELIGHT WHEN THEY FIND THAT ONTARIO LDC'S, UNLIKE THEIR AMERICAN COUSINS, WILL COMMIT TO TAKE THE GAS AND NOT SELF DISPLACE. SO FIGHT FOR SOME ADVANCE CAPABILITY IF YOU WANT TO HOLD MARKET.

LASTLY, I WOULD SUGGEST YOU WATCH OUT FOR THE "EMPTY PIPE RISK". WE OCCASIONALLY HEAR THE COMMENT THAT IF ONTARIO INDUSTRIAL CUSTOMERS FAIL TO CONTRACT LONG TERM, WE PRODUCERS CAN SIMPLY PULL THE GAS OUT OF THE MARKETPLACE AND MOVE IT TO THE EXPORT MARKET. IN MY OPINION THIS IS A SHORT-SIGHTED VIEW.

IN UNION'S CASE ALONE, SOME 70 BILLION FEET PER YEAR OF INDUSTRIAL MARKET CAN SWITCH TO ALTERNATIVE FUELS ALMOST AT THE DROP OF A HAT, UPON EXPIRY OF THE TYPICAL ONE YEAR CONTRACTS BETWEEN UNION AND THOSE CUSTOMERS. SHOULD SWITCHING GAS TO EXPORTS CAUSE SUCH A RESULT, THERE COULD BE LARGE AMOUNTS OF "EMPTY PIPE" BETWEEN ALBERTA AND THE BURNER-TIP. SOMEBODY IS GOING TO HAVE TO PAY THE FIXED COSTS OF THE DISTRIBUTION SYSTEM AND OF THE LARGE NEW TCPL EXPANSIONS RECENTLY PUT IN PLACE, AND ALTHOUGH THE MARKETPLACE CAN ABSORB SOME OF THIS, THE PRODUCERS' NETBACK WILL BEAR THE BALANCE. THE RESULTING REDUCED NETBACKS AND/OR INCREASED MARKET PRICES CAN RESULT IN FURTHER MARKET LOSS.

IN SHORT, SUCH A SITUATION CAN HAVE REAL NEGATIVE EFFECTS ON THE ENTIRE INDUSTRY AT BOTH ENDS OF THE PIPE. IT IS FOR THESE REASONS THAT WE ARE WORKING WITH OUR CUSTOMERS IN ATTEMPTING TO MOVE THEM TO A LONGER TERM BASIS IN GAS SUPPLY PLANNING, AND WE HOPE THE SUPPLIER END OF THE BUSINESS WILL TAKE THE SAME APPROACH RATHER THAN THE PUNITIVE APPROACH BASED ON FRUSTRATION WITH CUSTOMERS WHO, IN FAIRNESS, ARE REALLY JUST CONTRACTING AS THEY ALWAYS HAVE IN THE PAST WHEN THEY HAD DISTRIBUTOR SUPPLY.

SLIDE 22

MY LAST RECOMMENDATION IS FOR BOTH BUYERS AND SUPPLIERS, AND THAT RECOMMENDATION IS TO COMMUNICATE. FALLACIES DEVELOP WHICH CAN CAUSE FRICTION BETWEEN THE EAST AND WEST ENDS OF THE PIPELINE. THE MOST COMMON ONE, AS I DISCUSSED TODAY, IS THAT EASTERNERS HAVE SWITCHED TO SHORT TERM CONTRACTING AND BUYING LOTS OF SPOT GAS INSTEAD OF CONTRACTING LONG TERM. I HOPE I HAVE SHOWN YOU TODAY THAT THIS IS JUST ANOTHER ONE OF THOSE FALLACIES BUT CAN BE USED TO WHIP UP EMOTIONS. SUCH COUNTERPRODUCTIVE MISUNDERSTANDINGS CANNOT OCCUR IF WE TAKE SPECIAL CARE TO COMMUNICATE BETWEEN THE EAST AND WEST ENDS OF THE INDUSTRY, AND PARTICULARLY WITH OUR CUSTOMERS.

LADIES AND GENTLEMEN, THAT COMPLETES MY REMARKS AND I HOPE THEY HAVE BEEN OF SOME ASSISTANCE TO YOU IN YOUR GAS SUPPLY AND GAS MARKETING EFFORTS.

ONTARIO GAS MARKET DEVELOPMENTS

REMARKS BY

JOHN C. HUNTER
VICE-PRESIDENT, GAS SUPPLY
UNION GAS LIMITED
CHATHAM, ONTARIO

OCTOBER 24, 1989

CALGARY, ALBERTA

TOPIC OUTLINE

1. THE PRE-DEREGULATION SCENE
2. KEY EVENTS SINCE DEREGULATION
3. THE NEXT DECADE
4. RECOMMENDATIONS FOR BUYERS AND SELLERS

"THE WAY WE WERE"

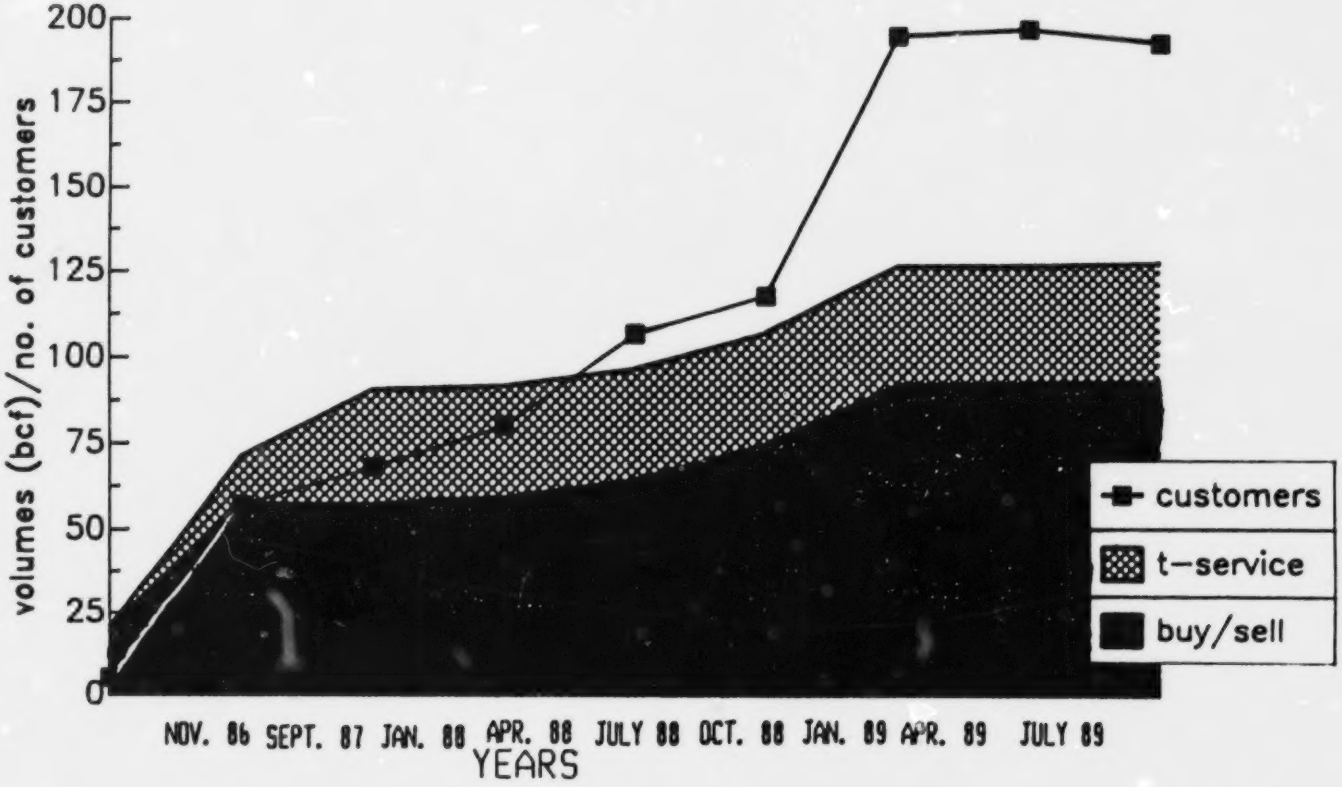
THE PRE-DEREGULATION SCENE 1975-1985

- PRICES (FIXED BY GOVERNMENTS) OUT OF TOUCH WITH MARKETS.
- ESSENTIALLY ONE SUPPLIER - TCPL - TO EASTERN MARKETS.
- MOST LDC'S LOCKED INTO TCPL SUPPLY TO 1995.
- LDC SOLE SUPPLIER OF GAS TO HIS MARKETPLACE.
- LOAD LOSS - DOMESTIC AND EXPORT - DUE TO INFLEXIBLE PRICE AND MARKETS.
- BUYERS AND SELLERS LACKED CHOICES.

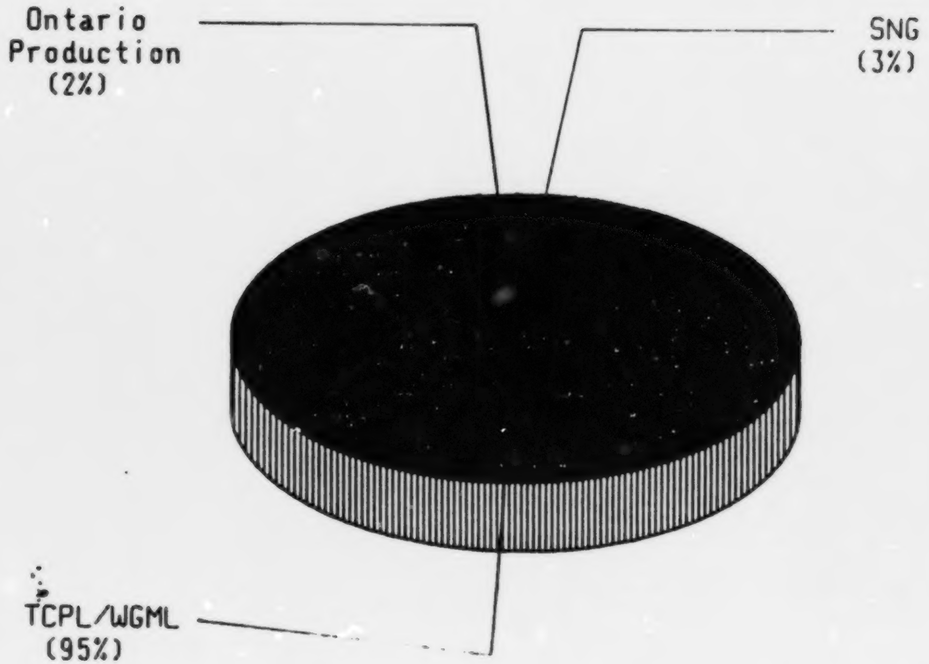
KEY EVENTS SINCE DEREGULATION

- OPEN ACCESS FOR END USERS ON TCPL
- MASSIVE DIRECT PURCHASE ACTIVITY
- GAS ON GAS COMPETITION
- TCPL/LDC RECONTRACTING
- REVIVED IMPORTS AND EXPORTS
- FTA/WEAKENED "SURPLUS TEST" PROTECTION
- NEW PLAYERS/NEW RISKS/NEW OPPORTUNITIES
- UNDERSTANDING THIN WHERE MORE NEEDED

DIRECT PURCHASE ACTIVITY

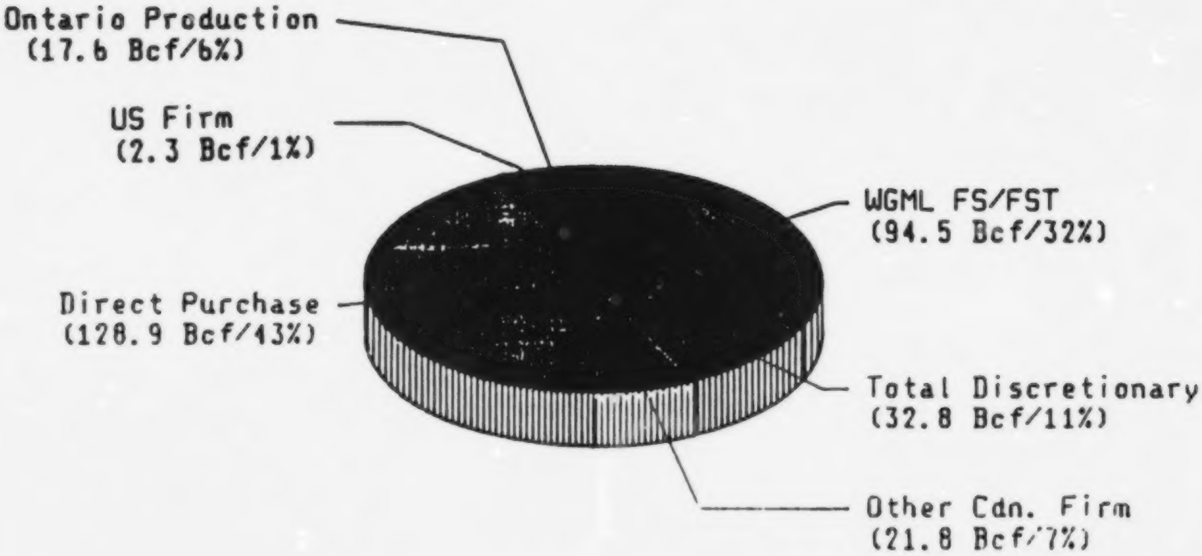


PRE-DEREGULATION
F'85



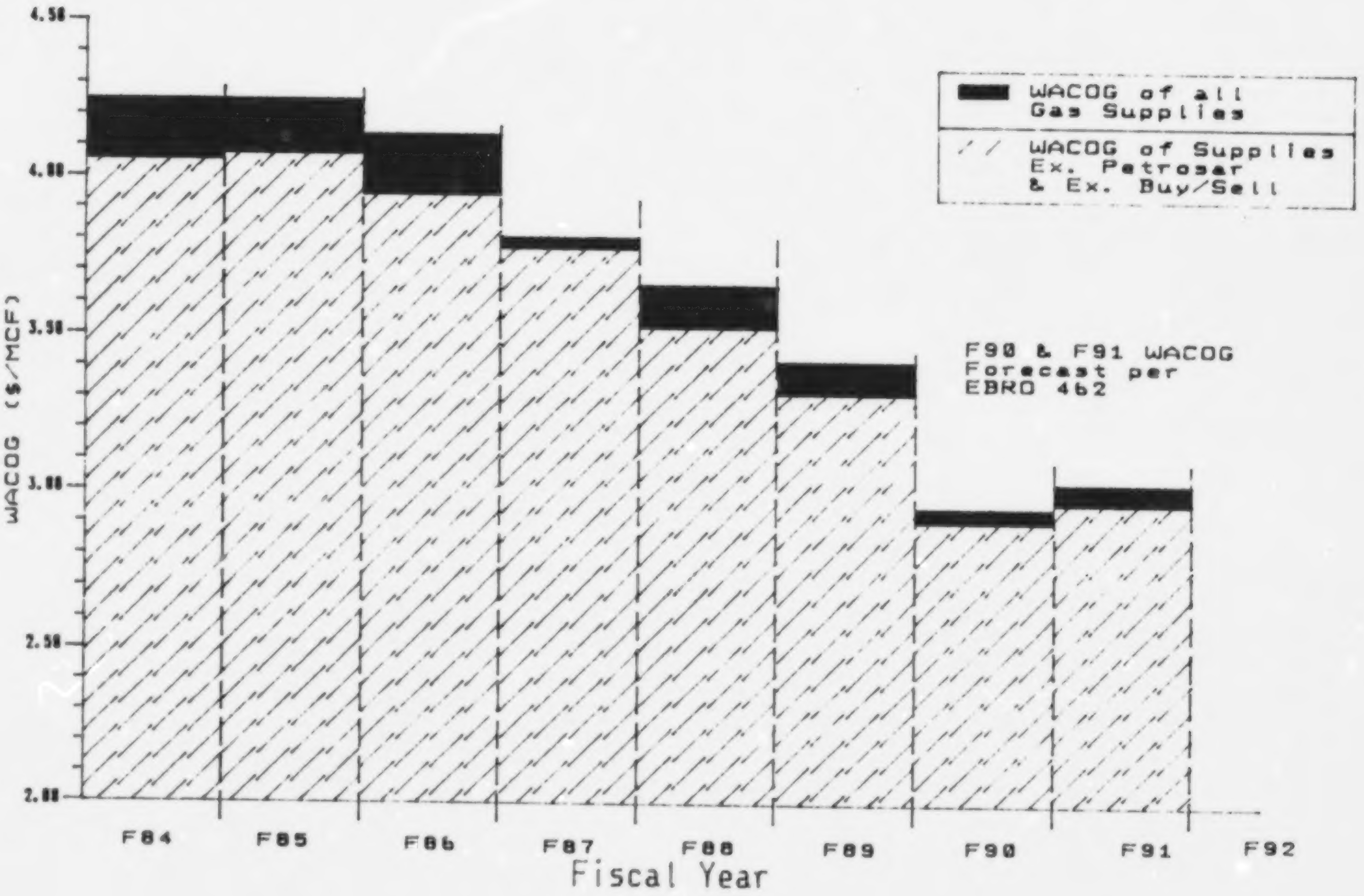
Total Supplies = 258 Bcf

UNION SUPPLIES 1990F
(Fiscal 90 Zero Qtr. Review)



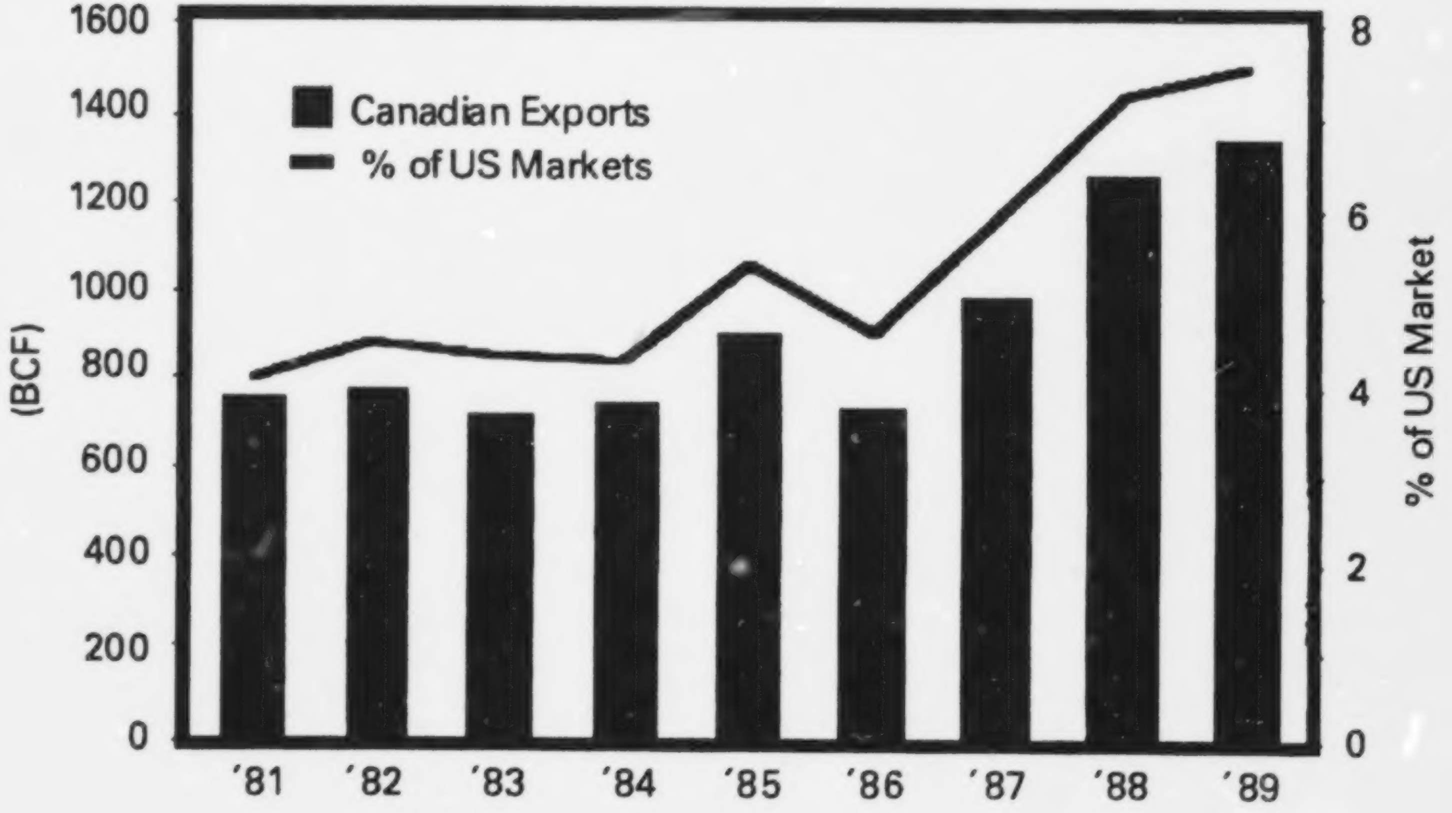
Total Purchases = 297.9 Bcf

HISTORICAL WACOG

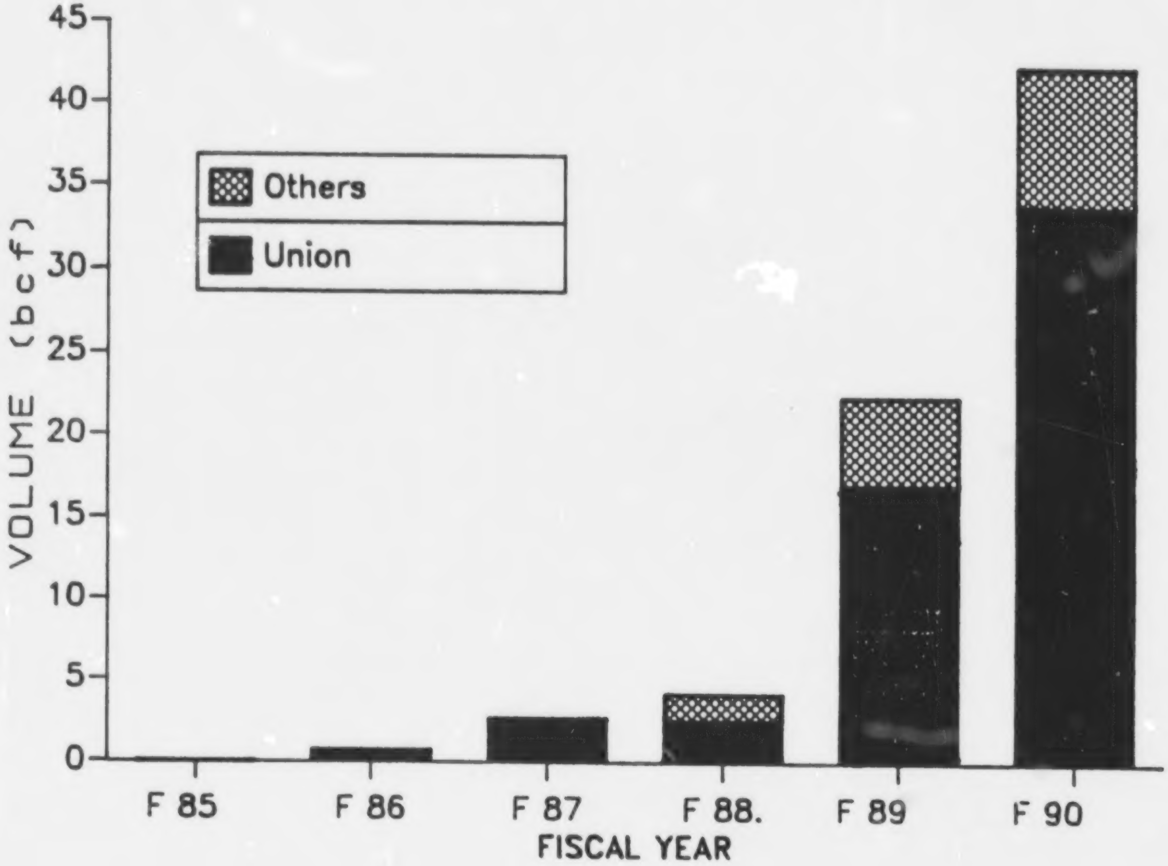


F90 & F91 WACOG Forecast per EBRO 462

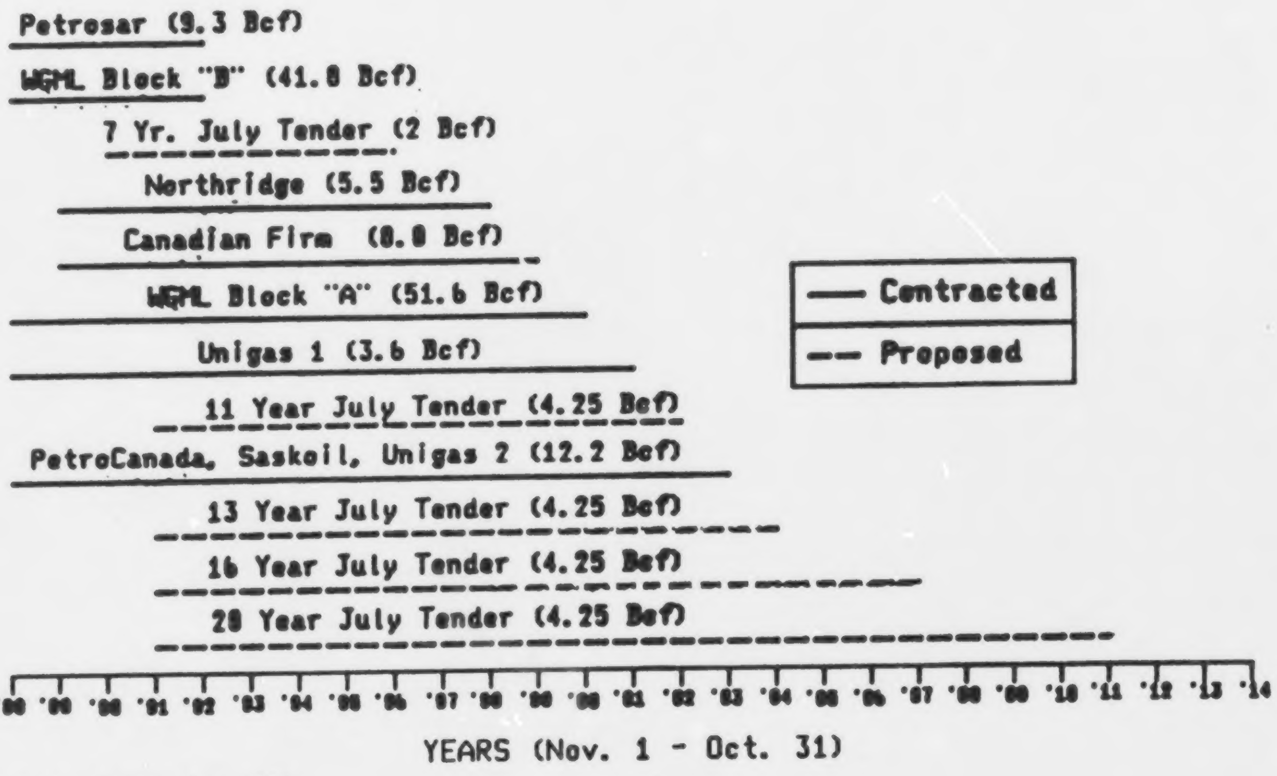
Canadian Natural Gas Exports



U.S. IMPORT VOLUMES

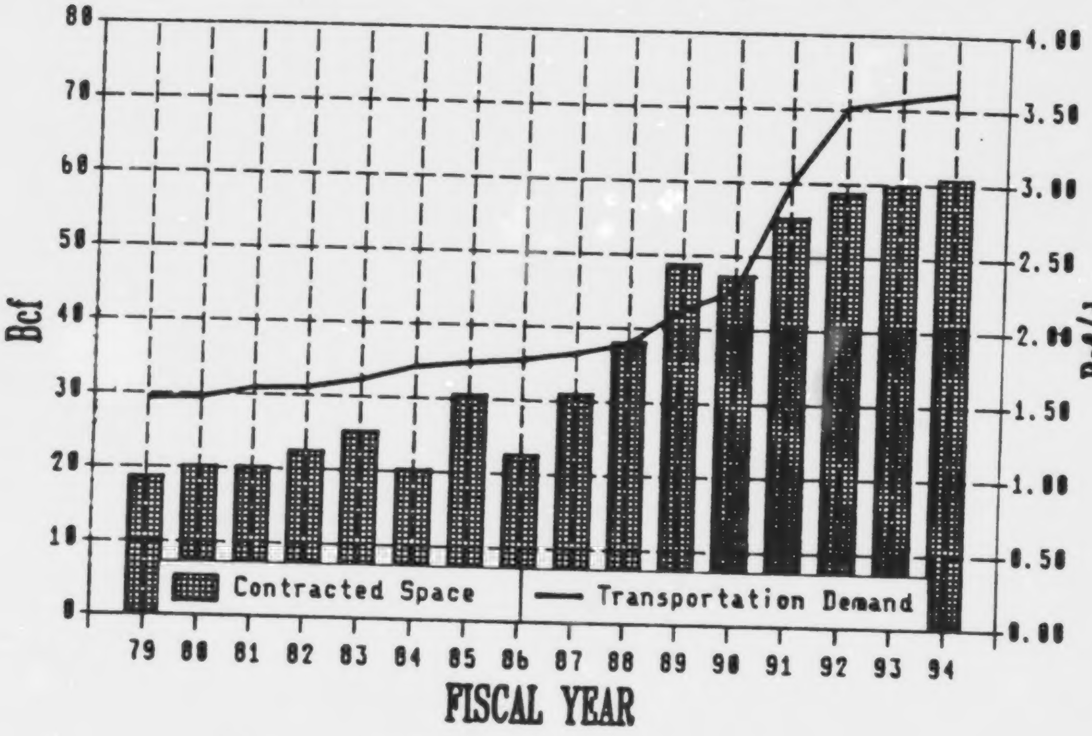


CURRENT AND PROPOSED LONG TERM CANADIAN GAS SUPPLY ARRANGEMENTS *



* As of July 24, 1989

Storage and Transportation Historical and Projected



Source: F1990 Zero Quarter Forecast

NOVEMBER 1, 1985 TO PLAN AT SEPTEMBER, 1989
CHANGE IN WEIGHTED AVERAGE TERM OF FIRM CONTRACTS

	% INCREASE OVER NOVEMBER 1/85
UNION	16
CONSUMERS' GAS	27
ICG ONTARIO	40
TYPICAL INDUSTRIAL	NO CHANGE - 1 YEAR

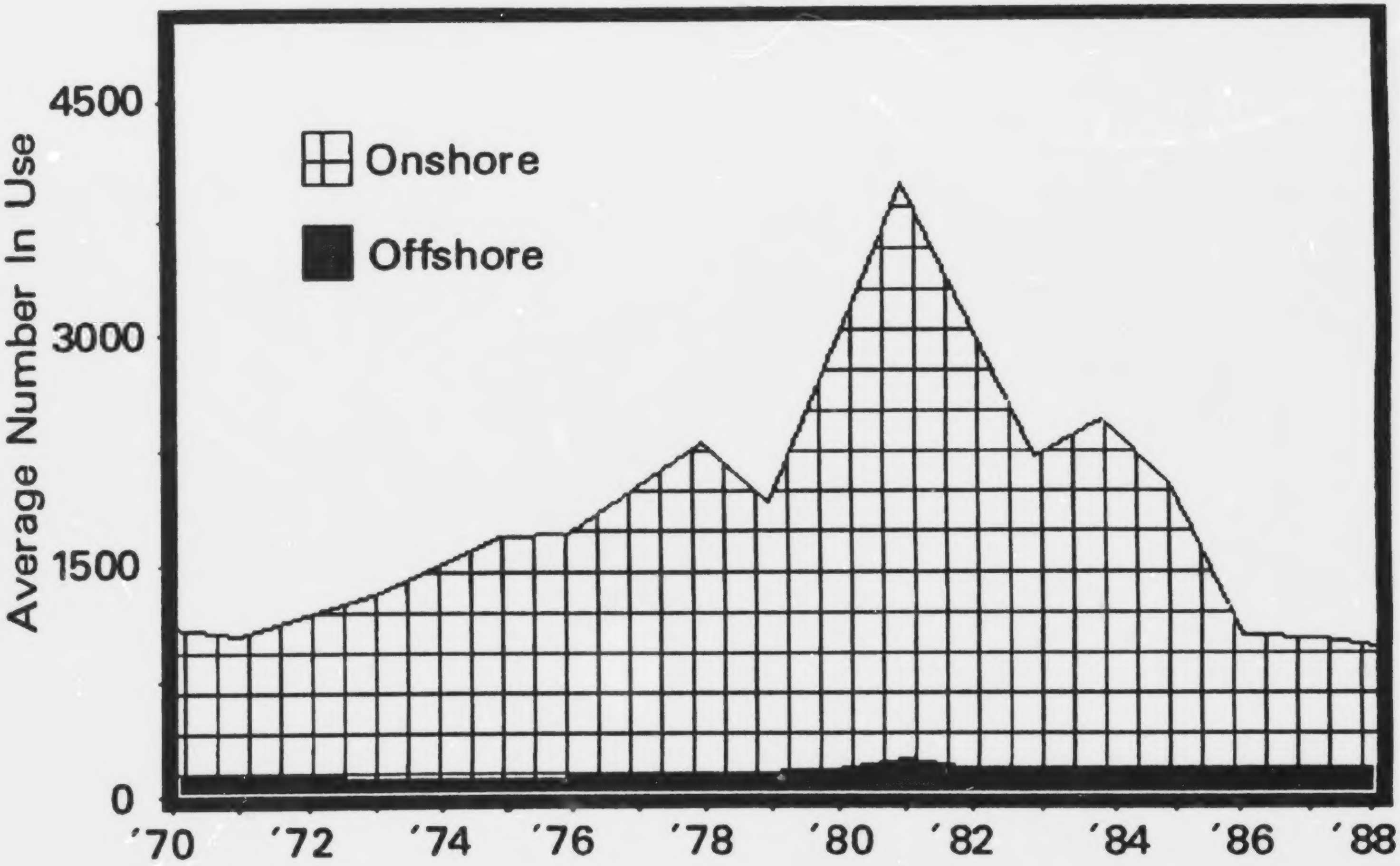
NOTE:
(1) EXCLUDES BUY/SELL AND BLOCK B VOLUMES, THE TERMS OF WHICH WERE NOT SELECTED FREELY BY LDC'S.
(2) INDIVIDUAL (VERSUS WEIGHTED AVERAGE) NEW UNION TENDERS ARE UP TO 20 YEARS.
(3) FIGURE FOR OTHER LDC'S ARE ESTIMATES ONLY.

Proved Reserves and Production of the Lower 48 States

Trillion Cubic Feet

Year	Reserve Additions	Production	Proved Reserves End of Year	Reserve Life (Years)
1980	15.4	18.5	165.6	9.1
1981	21.5	18.5	168.7	9.0
1982	15.1	17.2	166.5	9.8
1983	15.0	15.5	166.0	10.7
1984	13.9	16.9	163.0	9.8
1985	12.2	15.7	159.5	10.3
1986	14.7	15.3	158.9	10.4
1987	12.0	16.0	154.9	9.9
1988	6.5	16.0	145.4	9.7
1989	6.9	16.0	136.3	9.1
1990	6.5	16.0	126.8	8.5

Rotary Rig Activity



CANADIAN CONVENTIONAL DISCOVERIES ARE NOT KEEPING PACE

MARKETABLE NATURAL GAS REMAINING ESTABLISHED RESERVES IN CONVENTIONAL AREAS

(EXAJOULES)

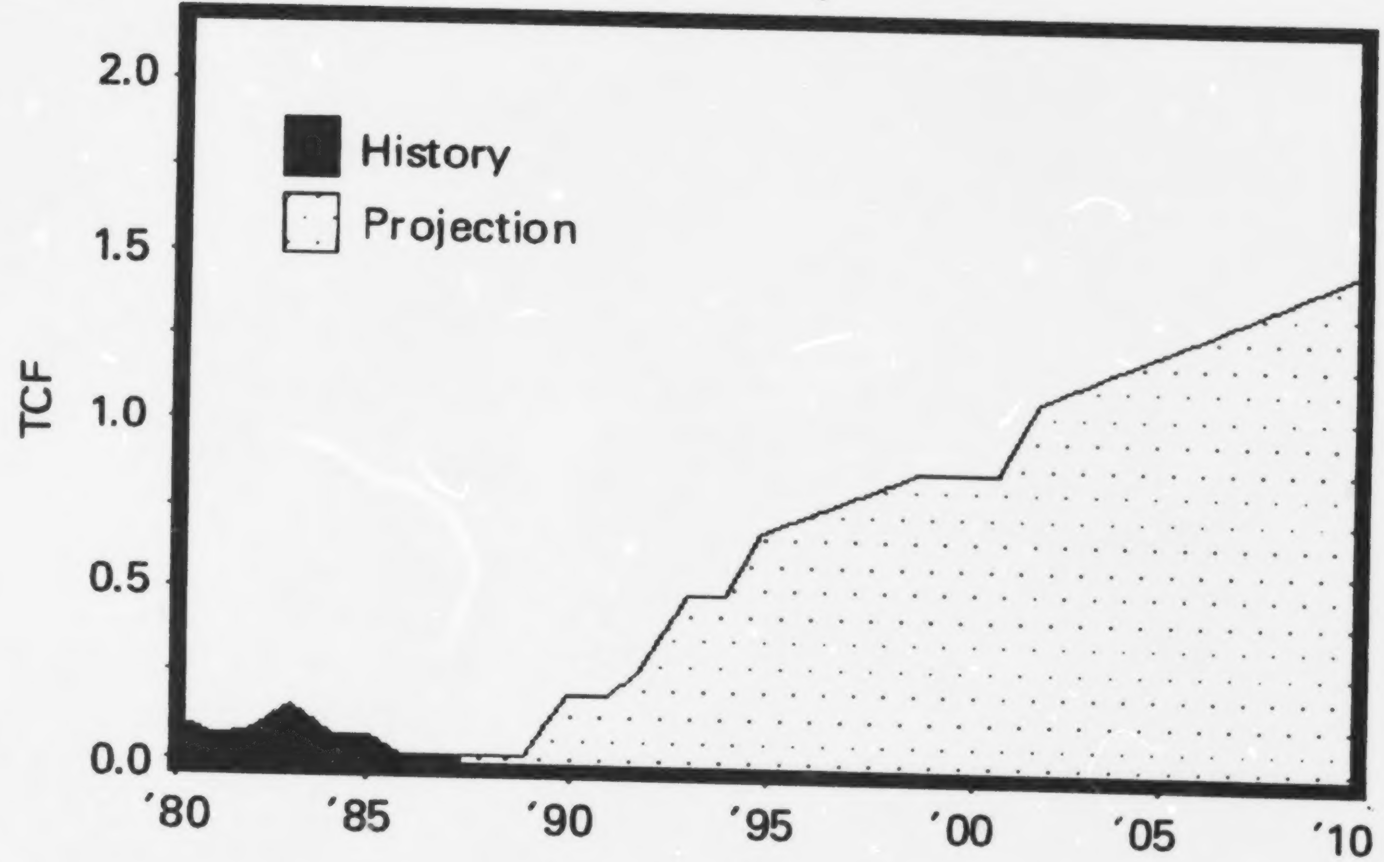
	REMAINING RESERVES BEGINNING OF YEAR	ADDITIONS			PRODUCTION	REMAINING RESERVES YEAR-END
		DISCOVERIES	REVISIONS & EXTENSIONS	TOTAL		
1982	80.8	0.7	2.8	3.5	2.8	81.5
1983	81.5	0.7	0.7	1.4	2.7	80.0
1984	80.0	0.4	1.1	1.5	2.9	78.6
1985	78.6	0.6	1.3	1.9	3.2	77.3
1986	77.3	0.5	0.8	1.3	3.1	75.3
1987	75.3	0.5	-0.3	0.2	3.2	72.3
1988 *	72.3	0.6	-0.2	0.4	3.6	69.1
1989 *	69.1	0.6	1.6	2.2	3.8	67.5

* ESTIMATED

UNCONTRACTED GAS SUPPLY IS SCARCE

ALBERTA ERCB (PAN ALBERTA HEARING)	TCF	
CORE MARKET	3.7	
CONTRACTED TO NON CORE	2.3	
FUEL/SHRINKAGE	4.0	
COMMITTED TO PERMITS	39.8	
TOTAL REQUIREMENTS	49.8	
		TCF
REMAINING ESTABLISHED RESERVES		60.8
LESS - 1/2 RESERVES BEYOND ECONOMIC REACH		1.0
- 1/2 DEFERRED RESERVES		3.2
TOTAL AVAILABLE RESERVES		56.6
AVAILABLE FOR PERMITTING AT DECEMBER 31, 1987		6.8 TCF

LNG Imports



ONTARIO - A VALUED MARKET

	NEW U.S. MARKETS	NEW ONTARIO MARKETS
GROWTH STYLE	OFTEN LARGE CONTROVERSIAL PROJECTS	. STEADY INCREMENTAL GROWTH - NORMAL COURSE OF BUSINESS . LARGE REPLACEMENT VOLUMES
REGULATORY APPROVALS	SOME OR ALL OF ALBERTA, NEB, FERC, ERA, LOCAL PSC, ENVIRONMENTALS,	ALBERTA, NEB, POSSIBLY OEB (FOR FACILITIES)
TIME LAPSE	3 - 10 YEARS	6 MONTHS - 3 YEARS
LOAD FACTOR	. AVERAGE EXISTING 66% . NEW PROJECTS 90+ ??	UNION 100%, CONSUMERS 100%, ICG 87+%
CONTRACTUAL ASSURANCE OF TAKES	VULNERABLE TO DIRECT PURCHASE AND SELF DISPLACEMENT	. GUARANTEE NOT TO SELF DISPLACE . CAN LOSE TO DIRECT PURCHASE

	NEW U.S. MARKETS	NEW ONTARIO MARKETS
POLITICAL RISK	YES	NEGLIGIBLE
REGULATORY RISK	SUBSTANTIAL	NEGLIGIBLE ON NEW DEALS
EXCHANGE RISK	YES	NO
TRANSPORTATION TOLL RISK ON PRODUCER?	GENERALLY YES (BURNER TIP NETBACK)	NO * (GAS PRICE SET AT ALBERTA BORDER, LDC PAYS TOLLS)

NOTE: * IF TOLLS RISE EXCESSIVELY THEY WILL BEGIN TO IMPACT NETBACK UNLESS THE PRODUCER PREFERS A LOAD LOSS TO OTHER FUELS.

RECOMMENDATIONS

BUYERS

- PLAN FOR TIGHTENING SUPPLY AND PRICE AND LEARN THE FACTS.
- PROTECT YOURSELF LONG TERM.
- DON'T EXPECT YOUR LDC CAN RESUME SERVICE ON SHORT NOTICE.
- AVOID UNDULY PUNITIVE CONTRACTUAL TERMS.

RECOMMENDATIONS

SUPPLIERS

- PERSONALLY LEARN YOUR MARKETPLACES.
- RECOGNIZE VULNERABILITIES OF EXPORT PROJECTS.
- DON'T TAKE ONTARIO MARKET AS CAPTIVE.
- LEARN AND EXPLOIT ATTRACTIVE ONTARIO LDC MARKET.
- PUSH FOR SOME ADVANCE CAPABILITY TO HOLD YOUR MARKET.
- WATCH THE "EMPTY PIPE" RISK.

RECOMMENDATIONS

ALL

COMMUNICATE!

PERSPECTIVES ON A "HOT"
MARKET FOR GAS

Presented by

Jacek Makowski
President
J. Makowski Company, Inc.
Boston, MA

EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

Introduction/Background

Chances are by now you've seen a fair amount of ink in the media about the Northeast energy market. You may have heard about the tremendous growth in electric demand during the past decade's economic boom. You may have followed the story of Champlain and Iroquois and the other Open Season gas pipeline projects. You also may have heard about the continuing questions facing the opening of two well-known nuclear plants - Shoreham and Seabrook. Yet another story that may have reached your ears is the re-start of LNG deliveries into the region. Chances are that your interest has been piqued.

Assuming such is the case, I shall attempt to use the next 15 minutes to apprise you of the situation and give you my views on how natural gas - the acknowledged fuel of choice in our region - can play a role in the Northeast's energy future.

Specifically, I want to:

A. Quantify the "new" growth market for gas in the NE - electric generation - and, in particular, Non-Utility Generation.

B. Explain the characteristics of the electric generation market and show why gas is competitive with other fossil fuels; and

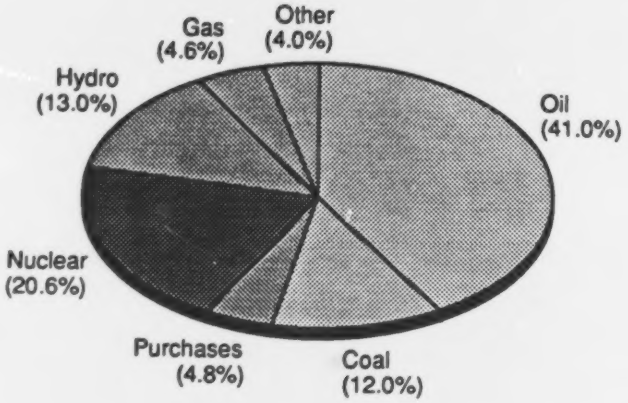
C. Give my views as to where that gas supply might come from.

First, a short preamble about my firm, J. Makowski Company, Inc., -- not exactly a Fortune 500 in size. The company was established in 1972 to provide specialized services; first to the gas LDC's in the Northeast and subsequently to the electric companies. In the beginning most of this work was gas supply consulting. This helped spur our eventual activities as an agent in purchasing gas as well as an equity investor in both gas and electric projects.

We had the opportunity to evolve as very major changes in the energy industry occurred over the past two decades. This allowed us to straddle the interface between the gas and electric sectors during (a) gas deregulation and (b) the evolution of alternative energy, PURPA and independent power projects. For example, our hydroelectric project in Lawrence was the first project to receive a PURPA exemption. The Boundary Gas project, which we helped to initiate and which we manage today, represents one of the first instances of a group of LDC's making direct purchases from then nontraditional suppliers (I note that LDC purchases of Canadian gas cannot be called "nontraditional" today). We are partners in the Iroquois Pipeline and conceived, organized and managed Ocean State Power in Rhode Island, which has been mentioned by FERC and state regulators as a model of the emerging Independent Power Production industry. Currently, we have equity positions in power projects totalling approximately 1,200 megawatts which are either in operation, under construction, or in permitting. We also currently administer long term contracts of some seven hundred million cubic feet a day of gas, of which about 92 million cubic feet a day is flowing. Full volumes are expected to flow in 1991/1992 time frame. In addition, we provide specialized consulting services to US and foreign governments, electrical utilities, LDC's, oil majors and various energy development companies.

Electric Generation - The "new" growth area

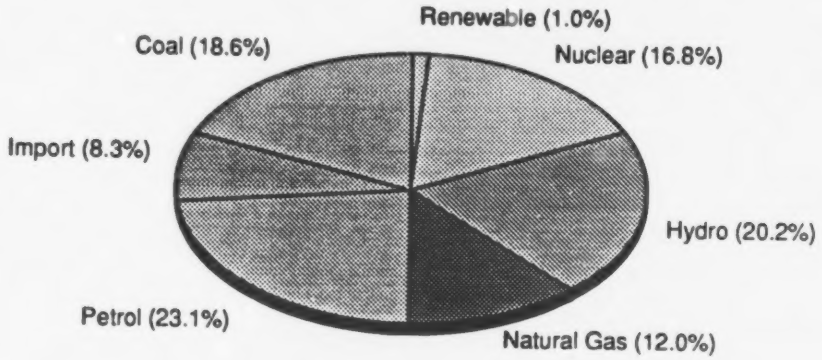
(Slide 1 & 2) The Northeast has a unique combination of assets and resources. When it comes to natural resources, we take great pride in our famous shorelines, islands, mountains and pastoral hills and valleys. In my home state of Massachusetts we often say that if the Pilgrims had landed in California instead, New England would be a national park today. But compared to our aethestic resources, our indigenous energy resources are practically nil. We are energy poor. This fact, combined with our geographic location, makes us different from the rest of the United States in terms of energy mix, with perhaps the most striking difference being the relatively low market share occupied by natural gas. In the area of electric generation our mix is also different as Figures 1 (New England) and 2 (New York) demonstrate. As electric demand continues to grow - and I'll give you more on this point in a moment - a key question facing the Northeast is not just what our future generation fuel mix will be, but what it should be.



NEPOOL Capacity by Generation Type
1988

Source: NEPOOL; Reed Consulting Group; April 1989

Figure 1



New York State Electric Generation
Fuel Mix - 1987

Source: Draft New York State Energy Plan; Volume VI; May 1989

Figure 2

(Slide 3) As you can see from Figure 3, the last three decades have brought a fair degree of turbulence to our electricity sector.

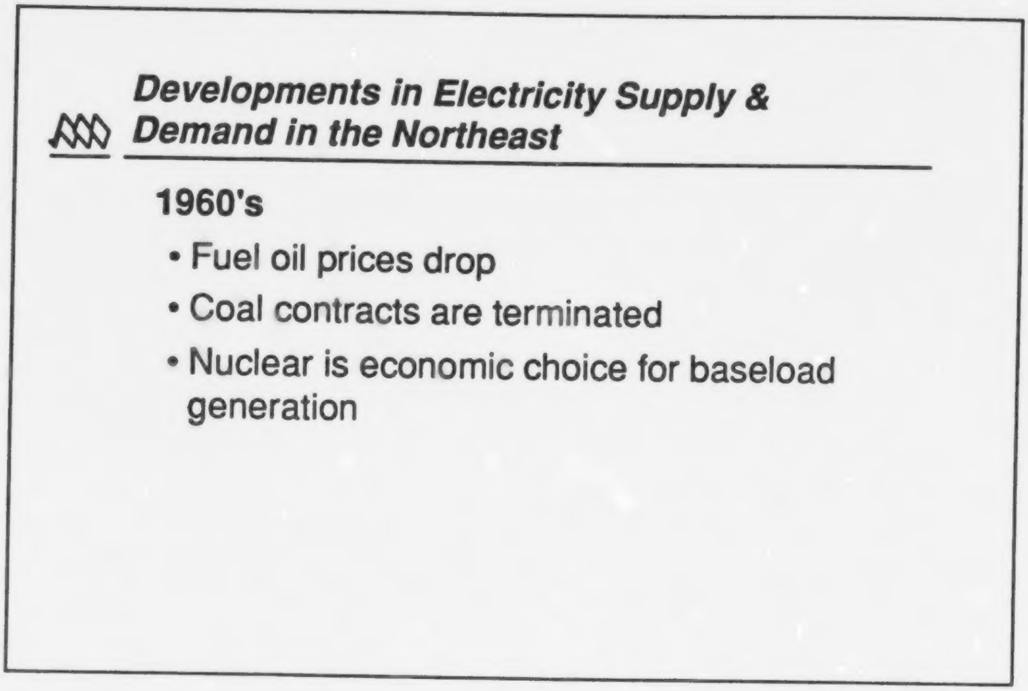
What will the 1990's bring? Some things I believe they will bring - in addition to opportunity for all of us in this room - are the following:

- Continued electrification in the commercial and service sectors; increased penetration of air conditioning and electronics will fuel the increase.
- Increase in the average age of existing plants - in some cases beyond the point of scheduled retirements;
- Continued increase in activities by NIMBYs - or as I like to call them when it comes to energy in the Northeast - SEBYs (As in, put it in "Someone Else's Back Yard")
- An increased role by Non-Utility Generators (NUGs) in the supply of incremental and replacement generation.

Let me now try to quantify this electric market for you (with perhaps the first step being to ask you to think of 100 megawatts as being equal to approximately 20 MMCF/d of gas required to fuel a gas-fired combined cycle plant). In my attempt to quantify the market, I want to give you an indication of not only what utility power planners in the region think but also what some of us highly interested parties on the periphery think.

Let me show you one reason why we have developed our own opinions.

(Slide 4) In Figure 4, you can see the growth in Peak Demand between 1983 and 1989 for the New England Power Pool, whose members account for more than 99.5 percent of the electric power production purchases and transmission in the six state region. As you can see, the growth has been somewhat spectacular with winter and summer peaks "leap-frogging" each other. More interesting, perhaps, is that all of these recorded peaks were hit long before their forecasted occurrence.



Developments in Electricity Supply & Demand in the Northeast

1960's

- Fuel oil prices drop
- Coal contracts are terminated
- Nuclear is economic choice for baseload generation

Figure 3

Developments in Electricity Supply & Demand in the Northeast

1970's

- 1973-74 Embargo
- No load growth in mid-70's
- Growth rates of 1 to 2% per year in late 70's
- Committed nuclear plants are cancelled; others under construction are delayed due to costs and regulatory requirements

Figure 3 Con't

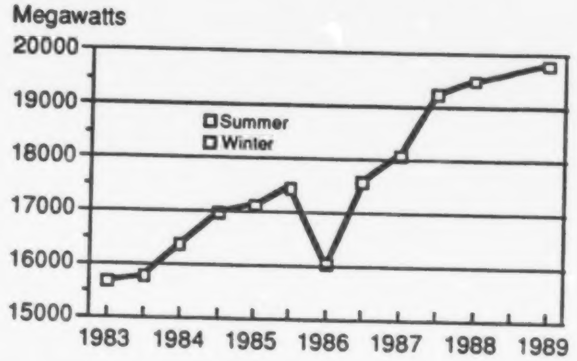
Developments in Electricity Supply & Demand in the Northeast

1980's

- Regional economy takes off
- Electric demand soars (e.g. New England load grows at 3 to 5% annually from 1982 to 1988)
- No new plant construction
- Reserve margins dwindle
- NUGs appear on the scene

Figure 3 Con't

NEPOOL Seasonal Peak Demand



Source: NEPOOL 1988 Annual Report

Figure 4

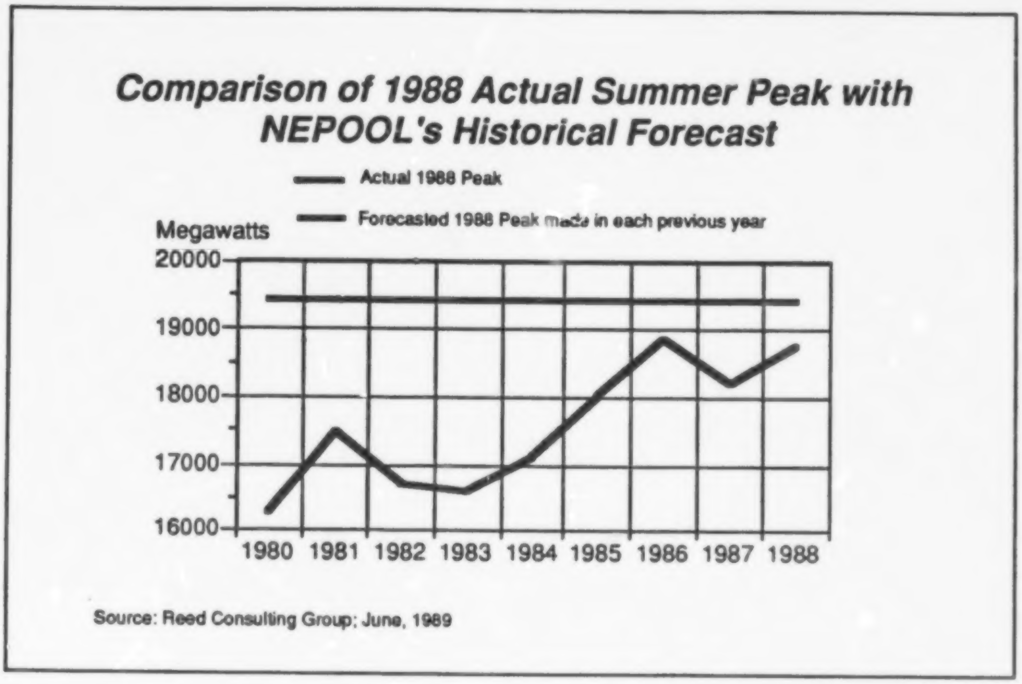
(Slide 5) While we all know forecasting is a no-win proposition, the fact is that, at least for NEPOOL, there is a record of consistent underprediction; Figure 5, which shows the progressive forecasts for the same target year is an example of what has happened.

Because of this record of underprediction and other factors, such as our differing views on treatment of NUG contributions, my company feels that the forecasts of NEPOOL and the New York Power Pool (NYPP) may be conservative as to what the real need is. Based on our own knowledge, our participation in the region's electricity "story" and an analysis by an independent consultant which we commissioned, we have come up with our own "reference" scenario which I would like to share with you.

(Slide 6) Figure 6 represents the additive supply and demand forecasts from the most recently published reports of NEPOOL and NYPP, with the following modifications:

- We have included 70% of prospective utility generation. We define prospective as being unspecified, umplanned utility - owned plants to be constructed in the future. While the pods have estimated an amount for such, they have not included it as a firm supply expectation. We have. (The pools do include planned plants; interestingly, two of those are assumed to be Seabrook and Shoreham).
- For NUGs, we have included both committed and uncommitted units (with the pools not including the latter). We have discounted those uncommitted NUGs by 60% to account for what we feel will be a likely success rate. The pools consider a committed NUG to be one that is under construction, has full regulatory approval, or some similar concrete status. As with their handling of utility owned plants, they do not include an unspecified (and therefore uncommitted) NUGS in their firm supply expectations.

For the record, Figure 6 displays two demand curves. The upper curve is forecasted demand with no Demand Side Management (DSM) contribution. The lower curve is with such a contribution. My only comment on DSM is that the utilities in our region do appear to be seriously embracing it as an option. Moreover, as evidenced by the reception of regulators to a recent proposal by new England Electric System, rate-of-return incentives which will compensate utilities for lost revenues appear to be on the horizon. As to how much DSM will occur and how fast it will arrive, only time will tell.

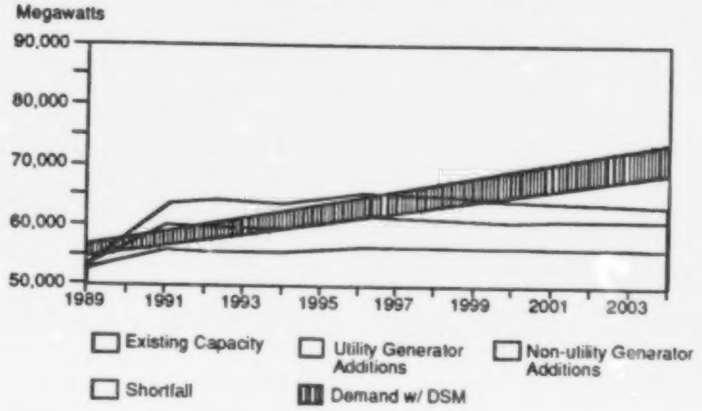


Comparison of 1988 Actual Summer Peak with NEPOOL's Historical Forecast

Source: Reed Consulting Group; June, 1989

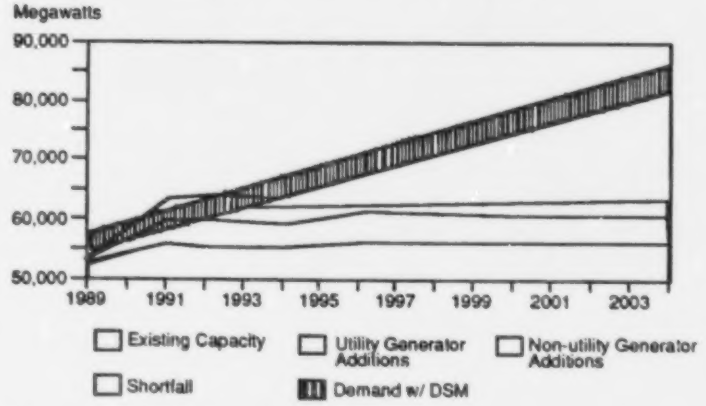
Figure 5

NEPOOL & NYPP Combined Supply and Demand Forecasts 1989 – 2004
Low Demand Scenario



Source; J. Makowski Co.; October 1989

Figure 6



NEPOOL & NYPP Combined Supply and Demand Forecasts 1989 – 2004 High Demand Scenario

Source; J. Makowski Co.; October 1989

Figure 7

(Slide 7) Figure 7 displays the same supply forecast as Figure 6 with the same respective supply-side adjustments. In this figure, the estimates for demand have been adjusted upward to a higher demand growth.

Let me now ask to look at the upper right of Figure 7 if your eyes have not been drawn to it already. What you see is a potential need of over 17,000 MW - on top of the 9000 MW of new generation capacity that is already included in the supply curves below.

Referring to our gas/electric equivalency test once again, this potential shortfall under a high demand scenario works out to a gas demand of 3,400 MMCF/d.

But will the Northeast's demand indeed be met by such gas amounts, or should we instead be looking at barrels of oil or tons of coal? My company believes gas is the only viable alternative. However, an increase in new gas-fired generating capacity will require increased understanding by electric utilities and gas marketers of each others' needs and requirements. Let me now turn to a brief discussion of what I feel you should understand about our market for electric generation.

Characteristics of the Electric Generation Market

There is a current ad campaign, at least in the States, that has as a tag line "It's not your father's oldsmobile". Let me apply that to the subject at hand and say that the Northeast market for gas-fired generation is "not your father's gas market". In the past this market may have been simply a seasonal or interruptible market for "dump" gas, however, that is no longer the case.

(Slide 8 & 9) The region needs baseload generation and the advantages of new Combined Cycle technology, (listed in Figure 8) allow gas to compete very well with other generating methods. Evidence of this can be seen in Figure 9, where one of my company's projects is placed on NYPOOL's load duration curve. This curve depicts the fuel component of the busbar cost of various technologies.

A combined cycle plant yields heat rates 20 to 25% below conventional oil-fired units. Recognizing that such plants cannot be fueled by Number 6 fuel oil, it follows that cogenerators and combined cycle plants can afford to pay a burnertip price between Number 2 fuel oil and Number 6 fuel oil. Figure 10 provides additional perspective on how gas can match up against competing fuels. It reflects my company's analysis of total levelized costs at the busbar for several fuel/technology combinations.

Advantages of Combined Cycle Technology

- Short construction period (less than two years)
- Low capital cost
- Low O&M costs
- Combines efficiency of a Steam Turbine with clean-burning properties of a Gas Turbine
- Low heat rates
- Meets environmental standards
- High availability factors
- Can follow daily load patterns to closely match dispatch requirements

Figure 8

New York Power Pool Load Duration & Generation Fuel Mix 1988

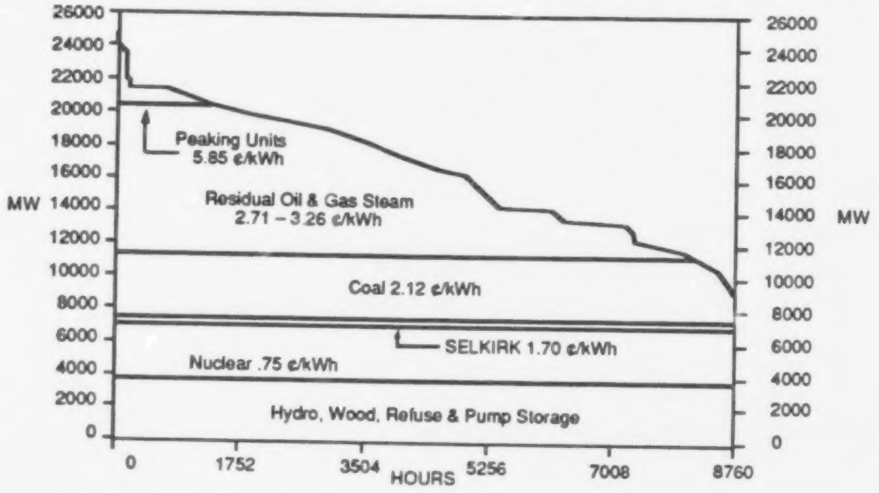


Figure 9

There are two other new and different characteristics of the Northeast Generation market today that are seemingly intertwined and of importance in terms of winning market share for gas.

The first is the increasing use of utility competitive-bidding systems as a procurement mechanism for new generation. The second, and as I said intertwined factor, is that the entities that are responding to the utilities competitive requests are NUGs.

A NUG responding to these bids often feels as though it is between the proverbial "rock and a hard place". It must try to convey the needs of gas producers to the utilities, but at the same time try to explain to a gas producer what the utility requires. In the same vein, a NUG often finds itself between the proverbial "chicken and the egg" where the potential electric buyer wants a project to have a gas contract before he buys and the potential gas supplier and transporter may insist that the NUG have a signed Power Purchase Agreement before reserves and transportation capacity can be dedicated.

But if we consider for the moment that the electric utilities are, after all, the buyer and the creators of this market, let us examine what the utilities in this market are currently asking for in their RFP's (Request for Proposals).

(Slide 11 & 12) Figures 11 and 12 represent a compilation for New York and Massachusetts, respectively, of the key fuel-related provisions of utility RFPs.

Let me return for a moment to a NUG's position as a bulk power supplier to an electric utility and tell you what is needed to satisfy the final party without whom this set of transactions cannot be consummated. That party is the financial community. The preferred choice of financing for NUGs is project financing - it is almost dictated by the entrepreneurial nature of the industry. But even though financiers like what they see in terms of market potential for NUGs, they are fiercely conservative in their lending practices. Most importantly, however, they look for long-term contracts covering electric sales and fuel procurement that will provide sufficient certainty to support project financing.

To summarize for the moment on the issue of gas procurement, let me list the three objectives that a NUG has when it attempts to secure a gas supply:

1) Long-term contracts (in the 12 to 20 year range) that will provide stability to both utilities and financiers;

Fuel Provisions in New York RFP's

Threshold Requirements

- Evidence of "Market Access" to supply and transportation
- Fuel Procurement Plan
- Correspondence from suppliers and transporters expressing intent to serve

Contract energy price

- Variable energy charge
- Variable and fixed transportation charges

Preferred fuel types (by point ranking)

- #1:Solid Waste, Hydro
- #2: Coal
- #3: Gas, Oil

Figure 11

Fuel Provisions in Massachusetts RFP's

Threshold Requirements

- Satisfactory evidence of access to delivered fuel
- Fuel procurement plan

Contract energy price

- Base price for delivered fuel escalated at one or more utility escalators – or request alternate utility projection
- No fuel pass-throughs
- Escalators
- No provision for Fuel Contract "Reopeners"

Fuel preference (by point ranking)

- #1: Wind, Hydro, Solar
- #2: Waste
- #3: Coal
- #4: Gas or Oil

Figure 12

2) Terms and conditions (in addition to duration of contract) that will support project financing; and

3) A price adjustment mechanism that indexes gas pricing to an appropriate market base of fuels or to a specific electric utility fuel index.

What else should you know about our generation market? With the introduction of President Bush's Clean Air legislation, the increasing concern over global warming and public apprehension regarding coal-fired generation, there are other pressures that favor gas-fired generation. Massachusetts has Acid Rain regulations that are tougher than those in the President's proposal. Both the 1989 New York State Energy Plan and the State of Rhode Island's recent Electric Generation Options Report endorse the use of natural gas over other fossil fuels. Relative to coal, local government officials and citizens are forcing projects already in development to pack up and leave their communities.

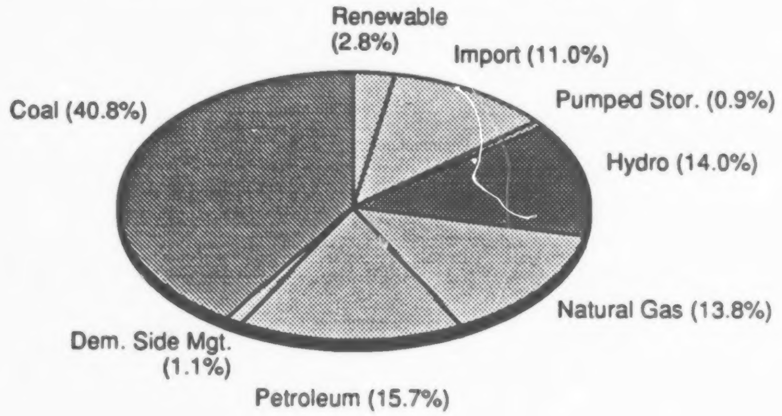
(Slide 13 & 14) The importance of environmental issues to growth in gas use can be seen in Figures 13 and 14. The first shows New York State's own projection for generation fuel mix in 2008 absent any change in environmental standards. The second graph shows the increased share of the generation market under tighter "low emissions" regulations.

Where will the gas supply come from?

In terms of natural gas, the northeast has been pipeline constrained for years. Existing capacity is fully contracted and fully utilized. Traditional pipeline suppliers have for the most part been unable to bring incremental supplies of long term gas at market clearing prices from the Southwest on a year round basis.

This situation is not going to be cured in the short term in toto. FERC's open season proceedings and the parallel proceedings in Canada have not, in my judgement, resulted in dedication of sufficient gas volumes and pipeline capacity to satisfy the market for both LDC's core markets and the needs of new power generation projects. The bottom line is that we will need substantially more gas from the Southwest and other sources in the coming decade.

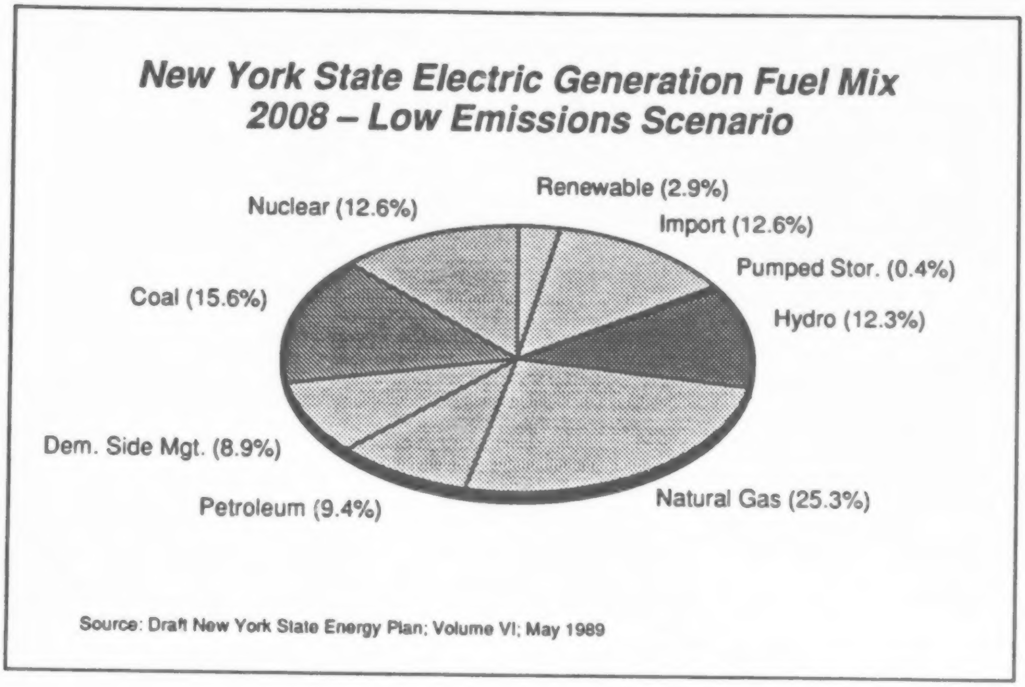
What are these potential sources? Obviously Canada is one, with its vast reserves as well as a pipeline delivery system, which is already integrated with the US pipelines and becoming more so with the advent of new pipeline expansions in most of the Northeast and in the Northwest. We also expect that LNG will play a resurgent and important role. I'm sure I do not have to describe to you the LNG plans and developments that have been extensively reported in the press. As far as my company is concerned, we have signed major contracts with Distrigas to supply two of our projects.



New York State Electric Generation Fuel Mix
2008 – Reference Scenario

Source: Draft New York State Energy Plan; Volume VI; May 1989

Figure 13



New York State Electric Generation Fuel Mix
2008 – Low Emissions Scenario

Source: Draft New York State Energy Plan; Volume VI; May 1989

Figure 14

Fuel Supply Options

- Natural gas will maintain significant advantages for Independent Power Producers particularly on the East Coast
- Southwest U.S. gas supply
- Canadian gas supply
- Non-traditional options
  - LNG
  - Innovative fuel combinations

Figure 15

1988 U.S. Imports

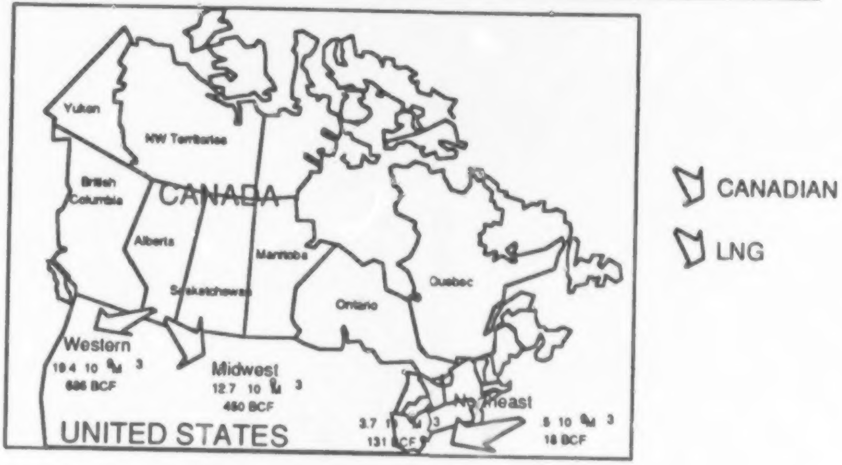
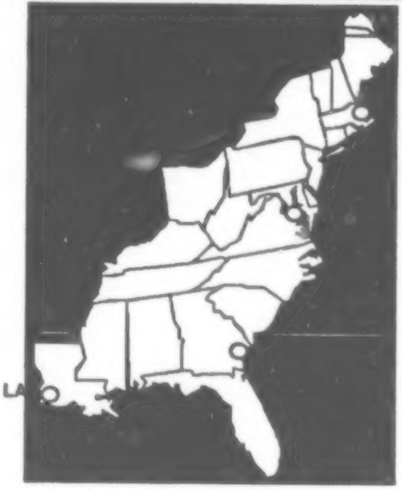

Yukon
NW Territories
British Columbia
CANADA
Alberta
Saskatchewan
Manitoba
Ontario
Quebec
Western
$19.4\ 10^9\ M^3$
686 BCF
Midwest
$12.7\ 10^9\ M^3$
450 BCF
Northeast
$3.7\ 10^9\ M^3$
131 BCF
$5\ 10^9\ M^3$
18 BCF
UNITED STATES
CANADIAN
LNG

Figure 16

LNG Receiving Terminals



EVERETT, MA
DISTRIGAS

8 10^6 M^3 /DAY
285 MMCF/DAY

COVE POINT, MD
COLUMBIA

28 10^6 M^3 /DAY
1000 MMCF/DAY

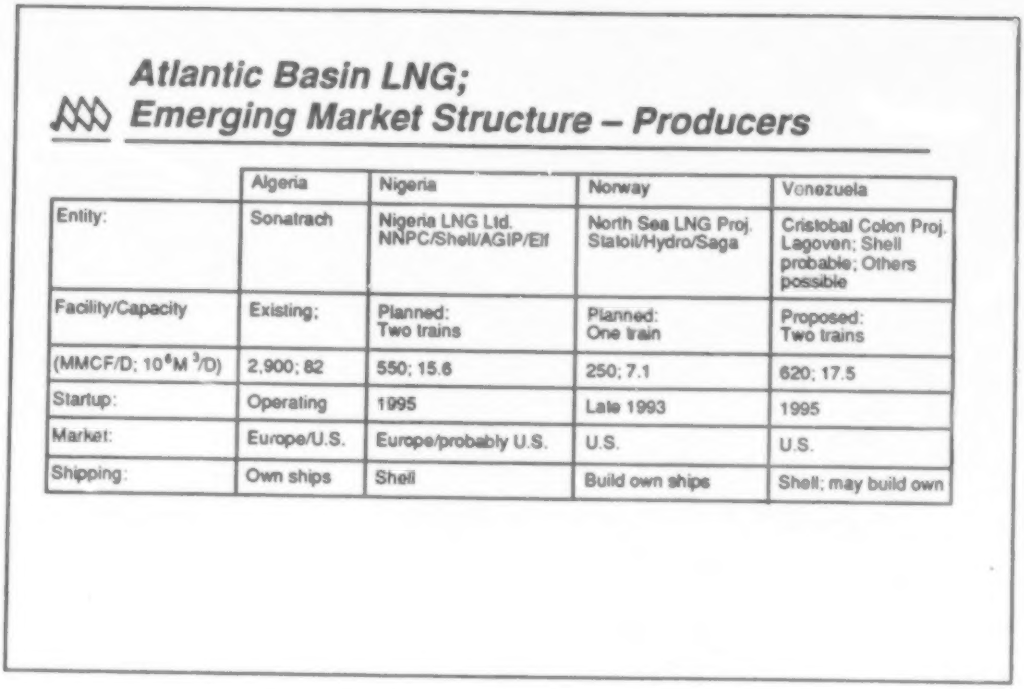
ELBA ISLAND, GA
SOUTHERN NATURAL

15 10^6 M^3 /DAY
540 MMCF/DAY

LAKE CHARLES, LA
PANHANDLE

20 10^6 M^3 /DAY
700 MMCF/DAY

Figure 17



Atlantic Basin LNG; Emerging Market Structure – Producers

	Algeria	Nigeria	Norway	Venezuela
Entity:	Sonatrach	Nigeria LNG Ltd. NNPC/Shell/AGIP/Elf	North Sea LNG Proj. Statoil/Hydro/Saga	Cristobal Colon Proj. Lagoven; Shell probable; Others possible
Facility/Capacity	Existing;	Planned: Two trains	Planned: One train	Proposed: Two trains
(MMCF/D; $10^6 M^3/D$)	2,900; 82	550; 15.6	250; 7.1	620; 17.5
Startup:	Operating	1995	Late 1993	1995
Market:	Europe/U.S.	Europe/probably U.S.	U.S.	U.S.
Shipping:	Own ships	Shell	Build own ships	Shell; may build own

Figure 18

We expect that the LNG will originate from a number of Atlantic basin countries and a diversity of supply will be achieved.

What about domestic sources? We come to the old issue of availability of pipeline capacity. Furthermore, any expansion of pipeline capacity will have to be financed by demand charges which probably will be the obligation of the power plant projects. In order to justify undertaking such obligations and achieve economic transportation rates, long term contracts will have to be entered between power plant projects and gas suppliers. One of the problems I have faced in discussing gas supplies with domestic producers in the Southwest is semantics. To me long term means fifteen years plus--to the producers five to ten years, to me a rapid permitting period means two years; to them six months.

Summary

Trees do not grow to the sky and the New England power market may not sustain this rapid rate of growth, but for each year where the growth is above forecast, the planning horizon closes. The options available for new generating capacity other than gas turbines grow more and more limited, especially because of permitting and construction time constraints for coal plants. Whatever the future growth will be, if it is between two and three percent, New England will need between 400 and 800 megawatts of new capacity every 12 to 18 months in order to preserve a 20 percent reserve ratio. If these new capacity needs are based only on gas, it would represent a new gas demand of 75 million feet a day to 150 million feet a day a year of growth annually. The shorter the time frame within which these new capacity amounts have to be met the fewer alternatives to natural gas power generation remain.

The market is there; it is going to be very large. The new plants are very efficient. The pattern of electricity use is the converse of gas, with the summer peaks being larger than the winter peaks. This leads to high load factor operation of the pipelines and the combination of all of these should lead to acceptable netback prices at the well head. I recommend this market be included in your strategic marketing considerations. Thank you very much.

> "Independent power production is one of the strongest markets for natural gas that I think we've seen in decades. ... A lot of whether or not the natural gas market share increases will be up to the producers and whether they're willing to sign long-term contracts. And frankly, if they are not, probably the Algerians are..."

Martha Hesse
Interview in August 1989 issue of *Natural Gas*

Figure 19

CALIFORNIA NATURAL GAS DEMAND

Presentation to the 8th CERI International
Oil and Gas Markets Conference
October 23, 1989

Richard A. Bilas, Commissioner
California Energy Commission

I INTRODUCTION

A. THE FOLLOWING AREAS WILL BE DISCUSSED

- California Oil and Gas Demand.
- California Sectional Demand.
- Comparison of CEC Gas Demand with the 1989 California Gas Report.
- California Gas Supply Sources.

B. GAS SUPPLY AND DEMAND FORECASTS

- Inputs to Electricity Report Process. we call it ER 90 Forecast.
- CEC will publish forecasts in 1989 Fuels Report, Dec. 1989
- Will include several sensitivities to the ER 90 Forecast.
  - high oil price forecast
  - environmental constraint on oil use in California.
  - these have not been completed

II CALIFORNIA DEMAND FORECAST

A. FIGURE 1
CALIFORNIA GAS AND OIL FORECAST

- Core Market has slight growth.
- Noncore market exhibits increasing gas demand.
- Oil use represents roughly 25% of Noncore demand.
    - Natural gas resource costs cause gas prices to bump against low oil price forecast

B. FIGURE 2
CALIFORNIA GAS DEMAND BY SECTOR

- Assumes all demand satisfied by gas.

C. WHAT THE FIGURES TELL US

- Principal Growth Sectors.
  - electric generators. (includes UEG & Cogen)
  - TEOR Steaming.
- Stable Sectors with Small Growths or Small Impacts on Changing Demand.
  - residential.
  - commercial.

D. NOTE THE DIP IN DEMAND FOR HISTORIC YEARS IN FIGURE 2

- 1984-1988 Actual Gas Demand.
- Forecasted years represent "normal" or "average" year conditions for all sectors.
- Early Forecasted years lower than historic use:
  - UEG used more gas than in an average year.
    1) dry years
    2) nuclear and coal plant problems
    3) shifted generation to gas

Figure 1

California Oil and Gas Use

Preliminary ER 90

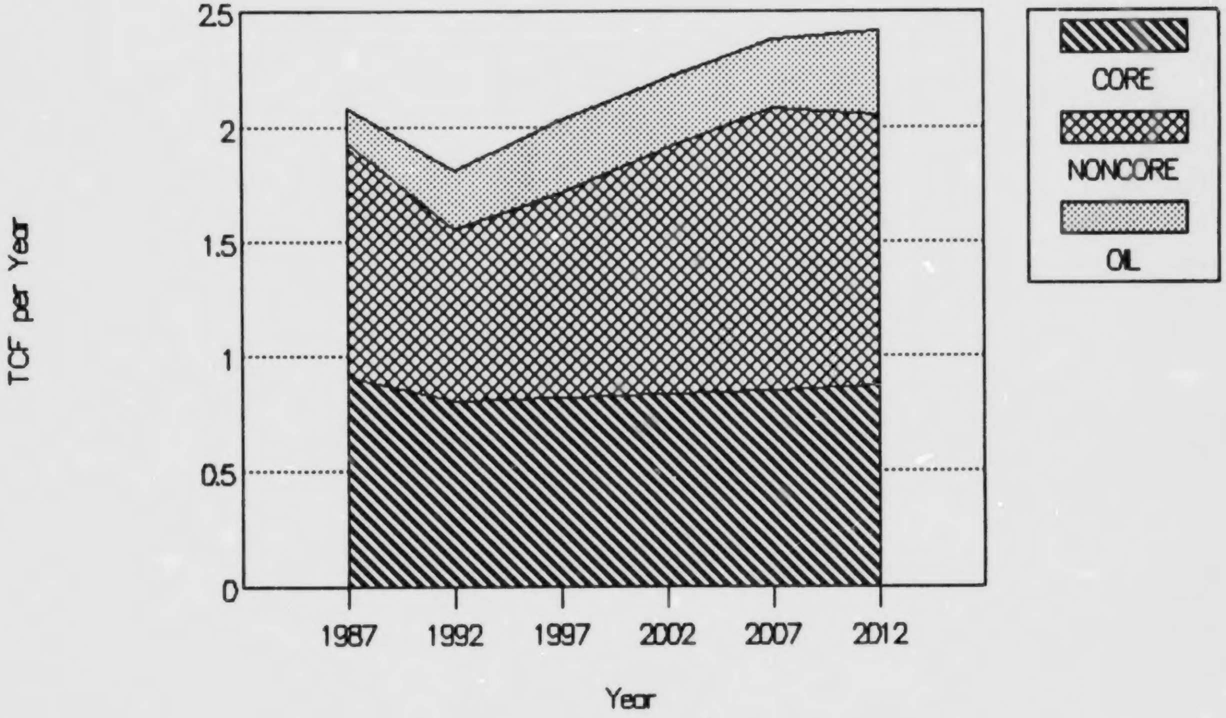
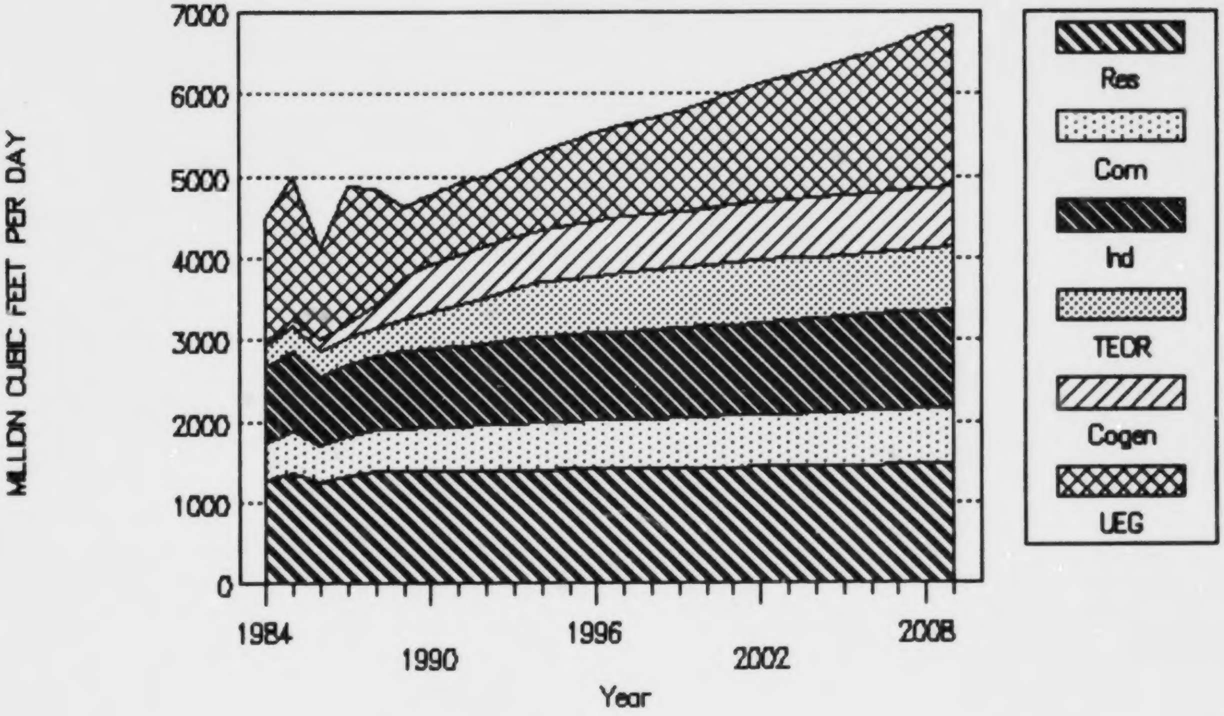


Figure 2

CALIF NATURAL GAS DEMAND

Preliminary ER 90



III CEC AND 1989 CRG DEMAND COMPARISON

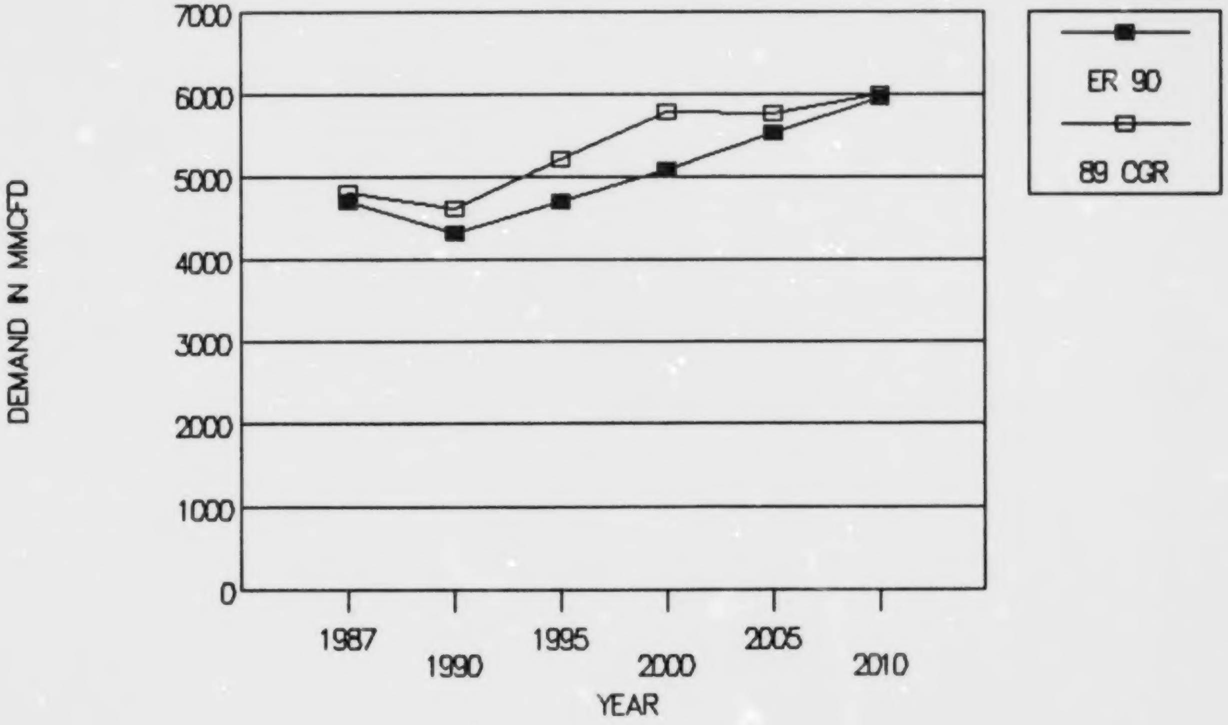
A. DEMAND DEPICTS POTENTIAL LDC GAS THROUGH PUTS
(Sales plus Transport)

B. FIGURE 3, TOTAL DEMAND FOR UTILITY GAS

- CGR Consistently higher for all years except start and finish.
- Interesting that CGR reaches a plateau around 2000.
(a pipeline capacity constraint?)

Figure 3

TOTAL DEMAND FOR UTILITY GAS
CEC AND 1989 CGR COMPARISONS



C. FIGURES 4 - 9, DEMAND BY SECTORS COMPARISON FOR SNAPSHOT YEARS

- CGR is consistently higher than preliminary ER 90

    1) in residential,
    2) TEOR,
    3) Cogen,
    4) UEG in early years.

- CEC consistently higher in utility service to

    1) commercial,
    2) industry,
    3) UEG in late years.

Note: Maybe definition differences in Cogen. CEC determines all process heat requirements using conventional equipment. Cogen is the incremental gas need if conventional equipment is swapped for cogeneration equipment. Gas utilities may include total cogen fuel requirements under cogen, or use the same definition as the CEC or use a mixture of the two.

Figure 4

1987 DEMAND FOR UTILITY GAS

CEC AND 1989 CGR COMPARISONS

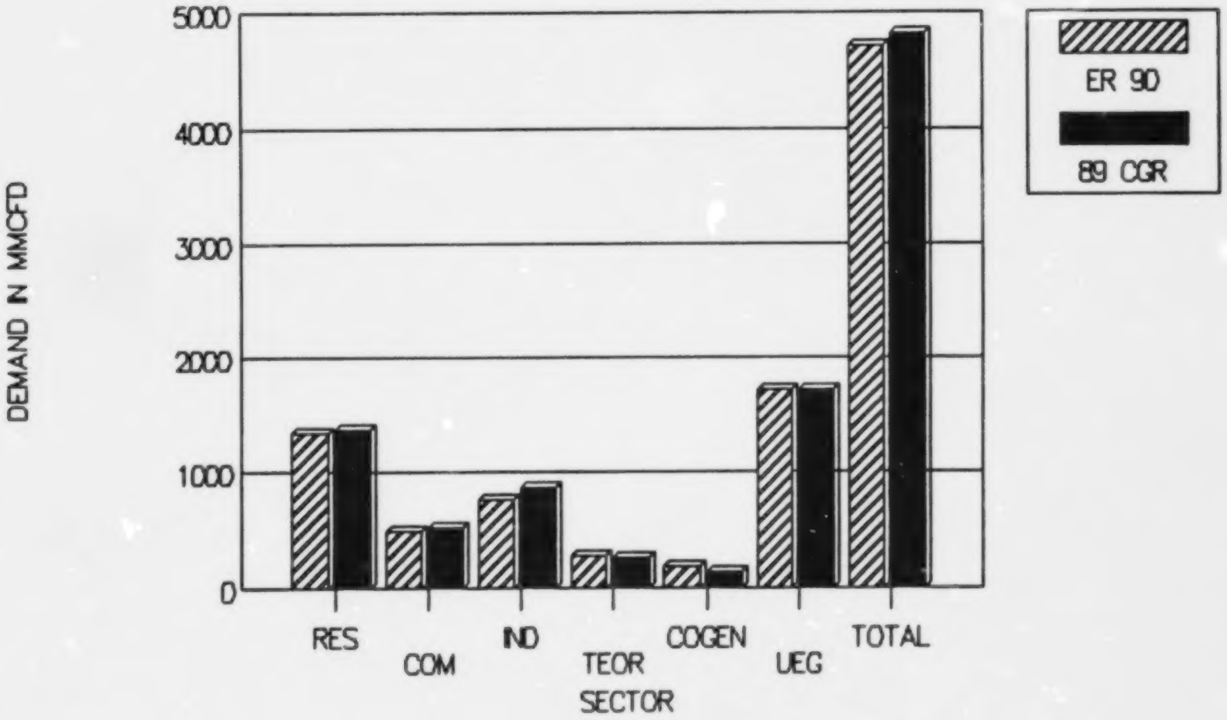


Figure 5

1990 DEMAND FOR UTILITY GAS
CEC AND 1989 CGR COMPARISONS

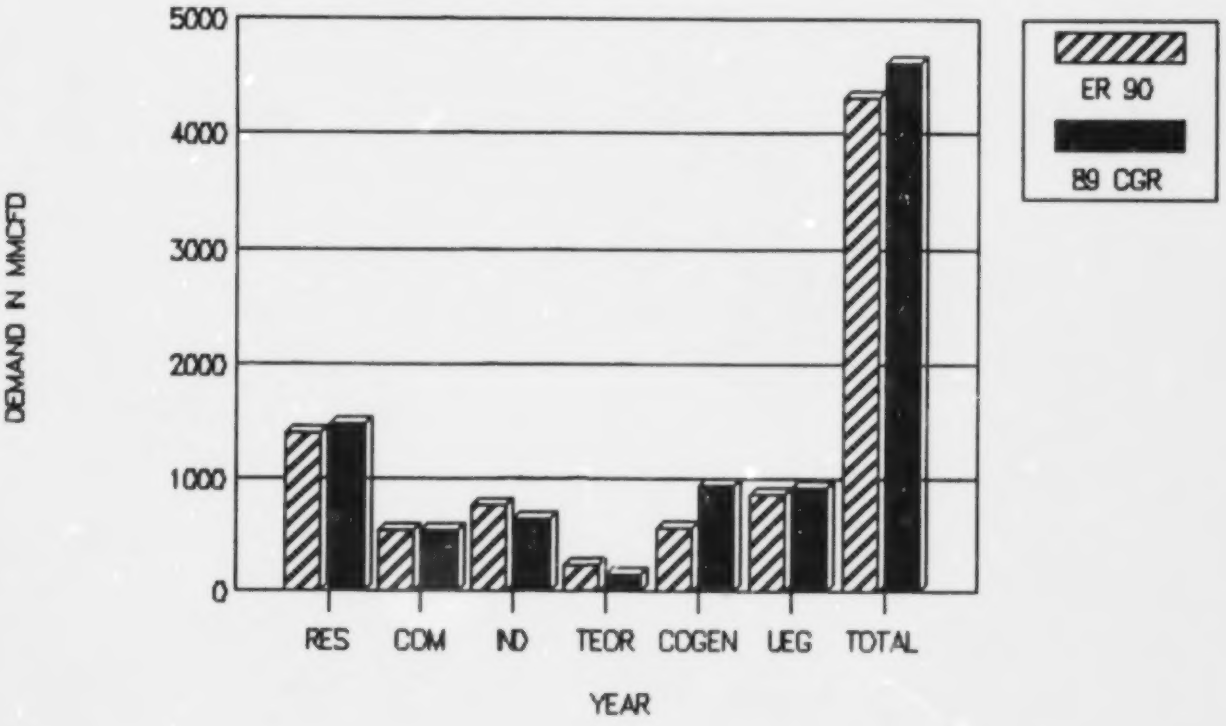


Figure 6

1995 DEMAND FOR UTILITY GAS
CEC AND 1989 CGR COMPARISONS

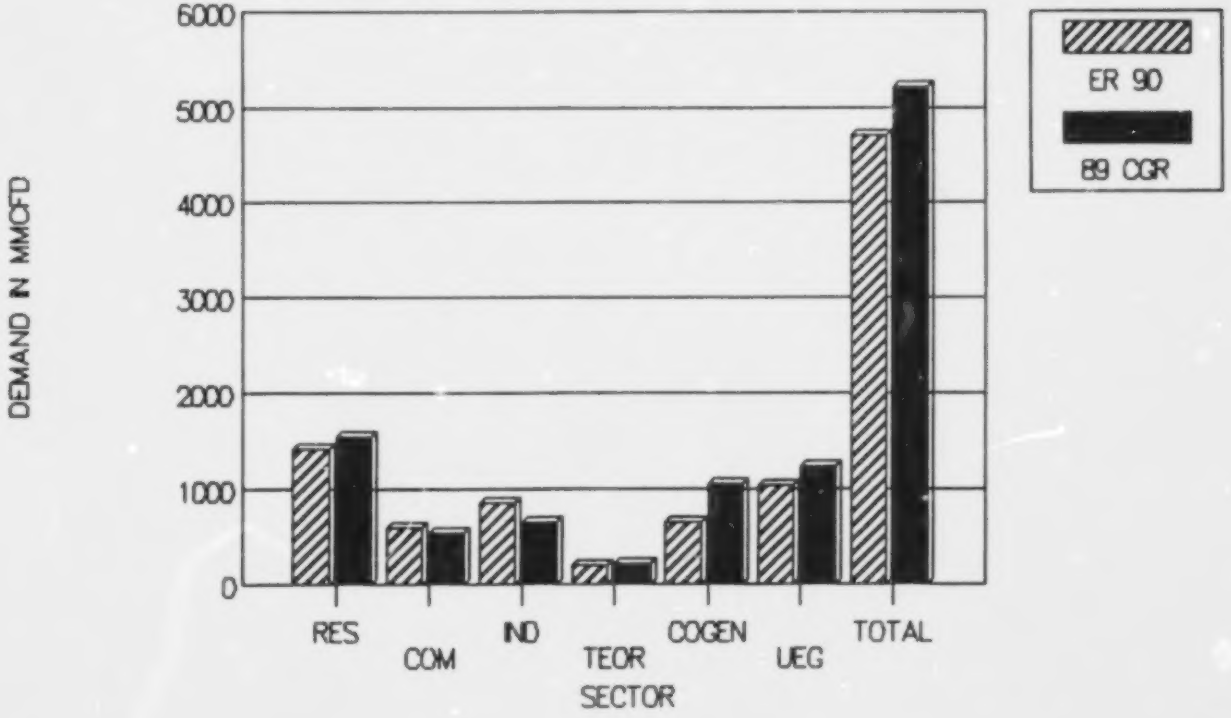


Figure 7

2000 DEMAND FOR UTILITY GAS
CEC AND 1989 CGR COMPARISONS

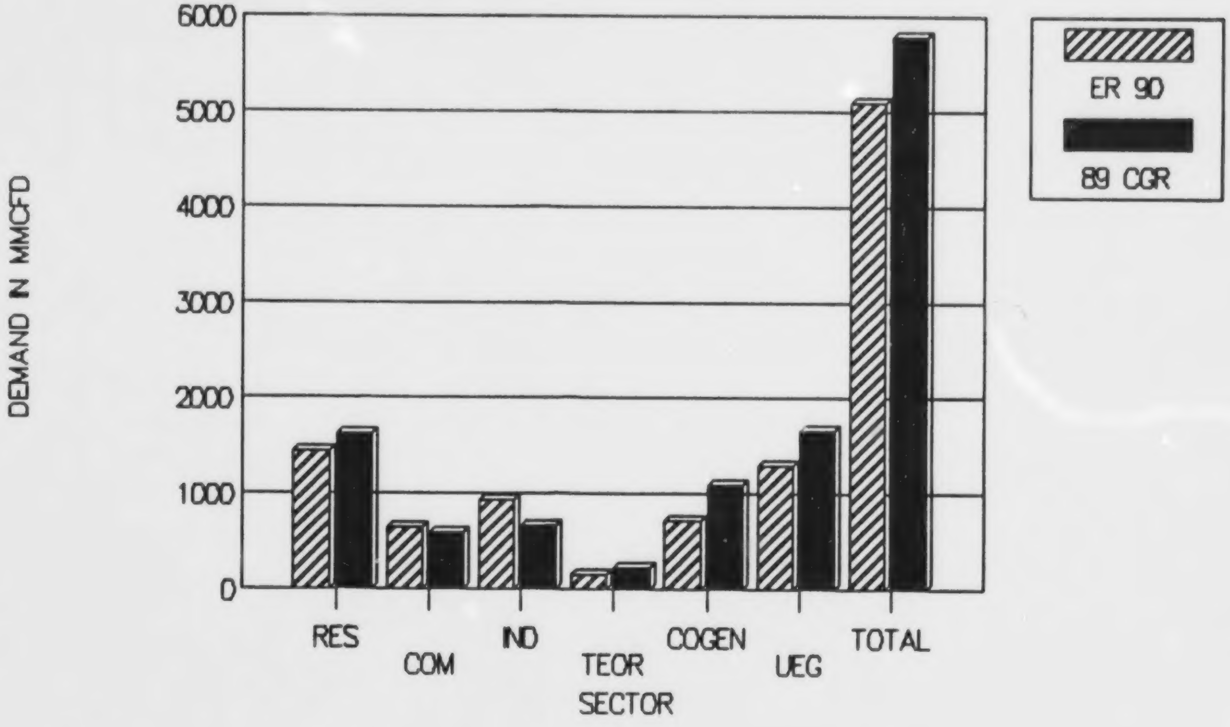


Figure 8

2005 DEMAND FOR UTILITY GAS

CEC AND 1989 CGR COMPARISONS

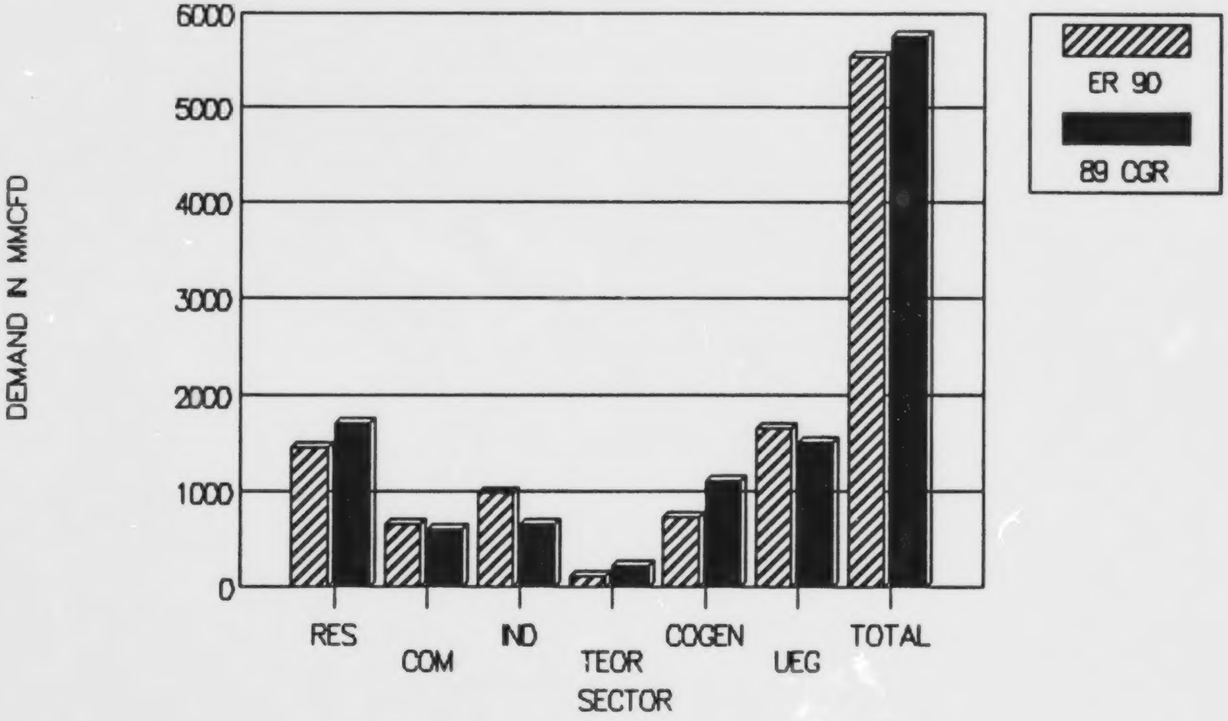
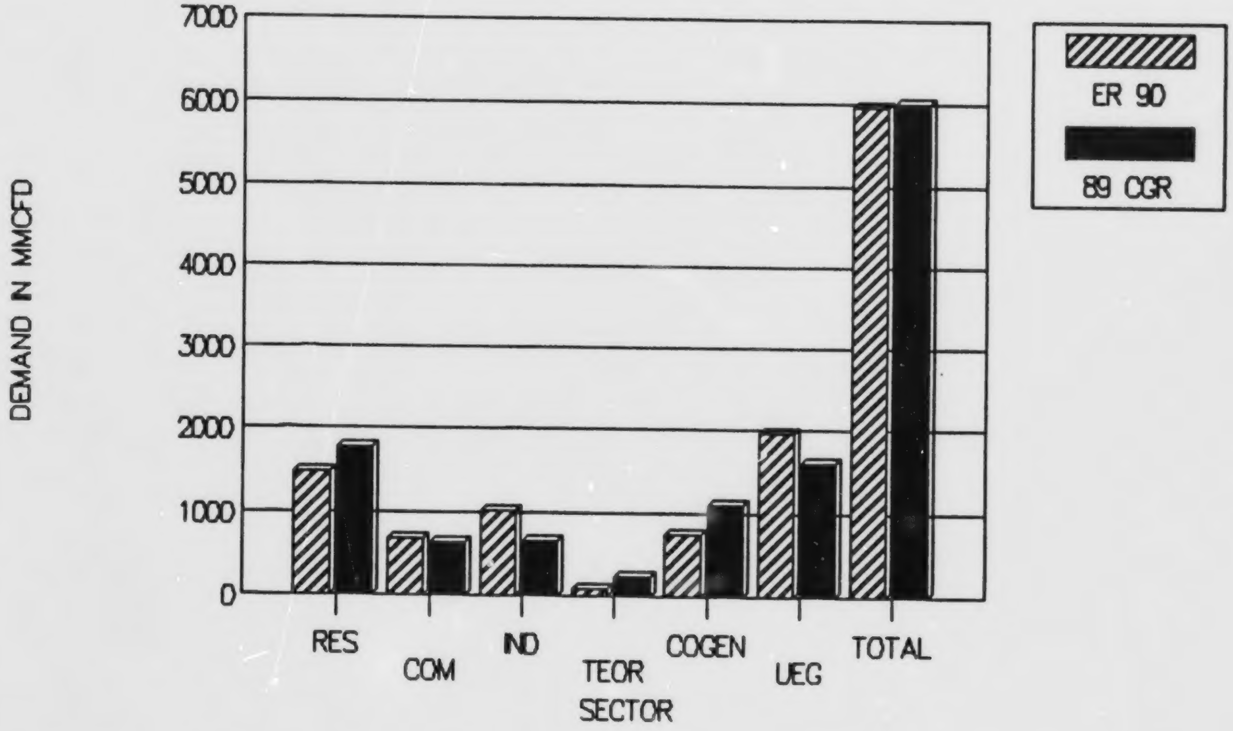


Figure 9

2010 DEMAND FOR UTILITY GAS
CEC AND 1989 CGR COMPARISONS



IV CALIFORNIA GAS SOURCES

FIGURE 10

A. CALIFORNIA SOURCES OF FUTURE GAS SUPPLIES

- Southwest remains largest source of gas. Deliveries are held up by coal seam production from San Juan Basin.
  - Permian/Anadarko production increases but flows east
- Canada increases share of California market.
- Rocky Mountain supplies grow.
- California production declines.

B. ASSUMPTIONS CONCERNING GAS SUPPLY ESTIMATES

- Used NARG Model.
- New pipelines constrained to proposed capacity.
  - PGT Loop
  - Rocky Mountains
  - Altamont
  - Mojave
- Existing pipelines are allowed to grow as needed.
- Trail Blazer/Northern Border settlements and expansions are included.
- More direct routing for BC gas to California.
  - 150 to 200 mmcfd in late 1990s to 2000
- Coal seam resources increased to 25TCF.
- Remaining resources are unchanged from Pipeline Economic Study.
- Delphi Oil Price Forecast
  - increases from $15/bbl in 1988 to $26/bbl in 2009 (all in 1988 $)

Figure 10

California Supply Sources

Preliminary ER 90

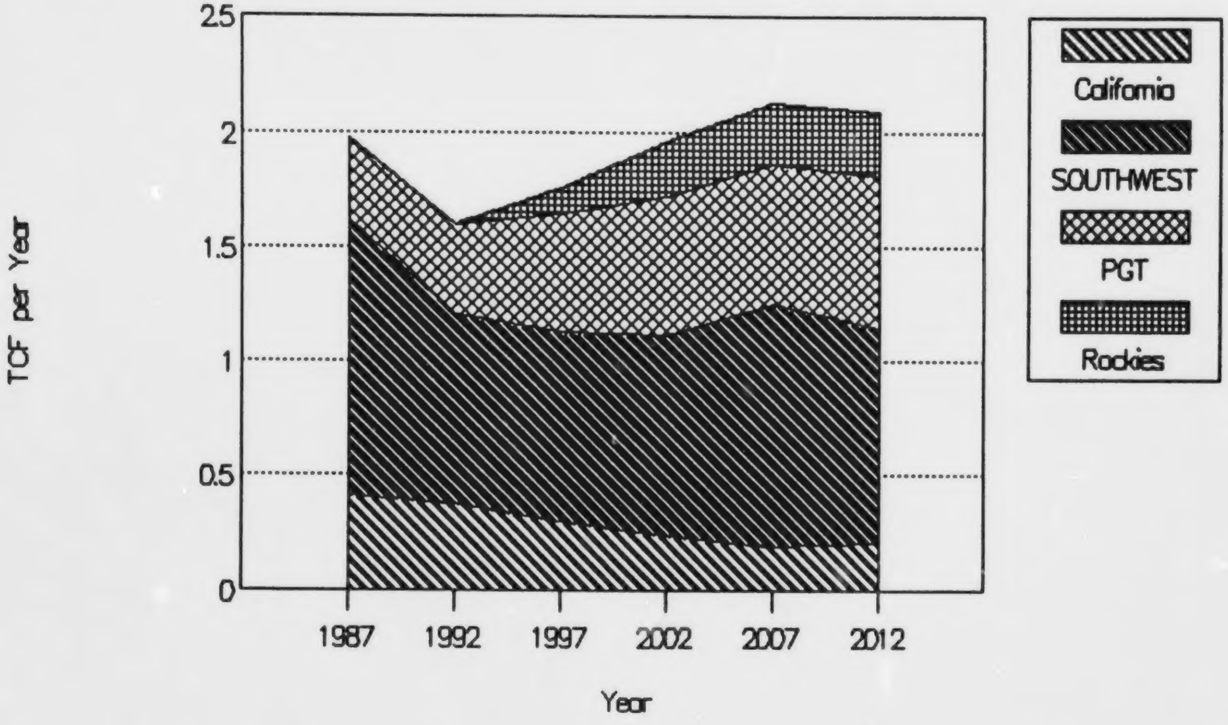


FIGURE 11

C. NORTHERN CALIFORNIA SUPPLY

- Canadian Supply commands large part of Northern California market.
  - Both B.C. and Alberta contribute to supply via PGT Loop
- Southwest Supply grows after 1992.
  - Principally Coal Seam Gas from San Juan Basin.
  - East New Mexico/West Texas gas increases but flows east.
- California production declines.
- Rocky Mountain Pipeline gas has only a small penetration to Northern California.

Figure 11

Northern California Supply

Prelimianary ER 90

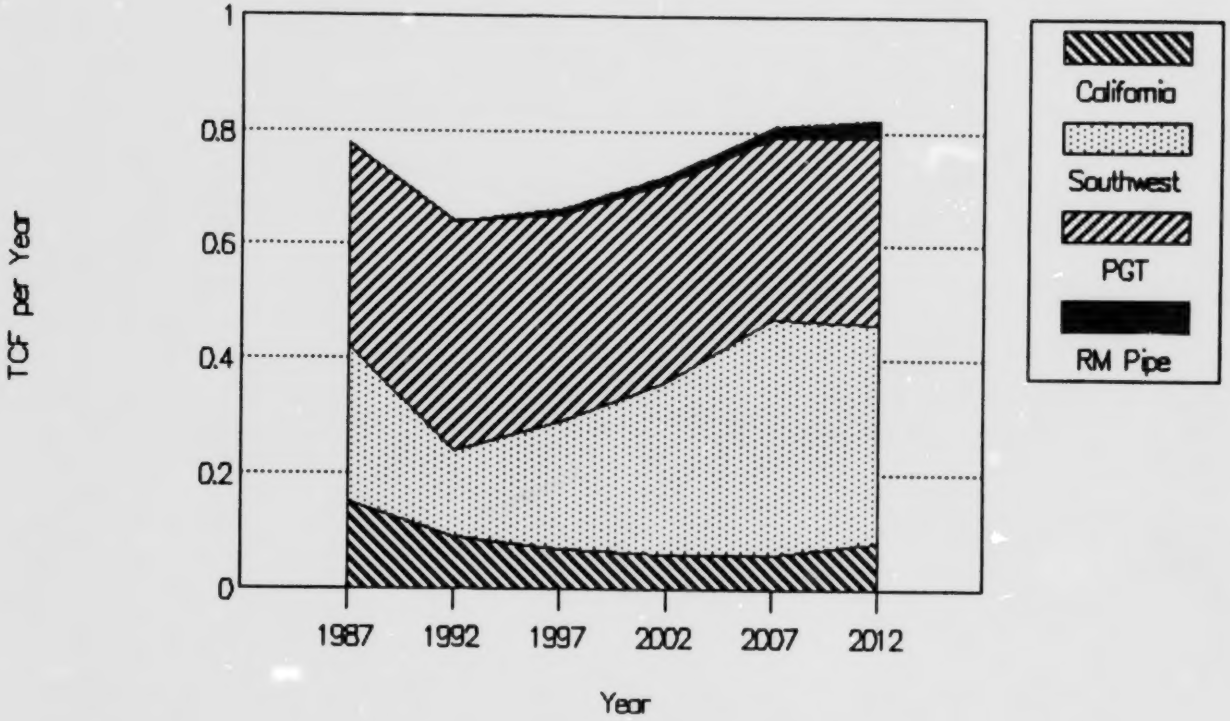


FIGURE 12

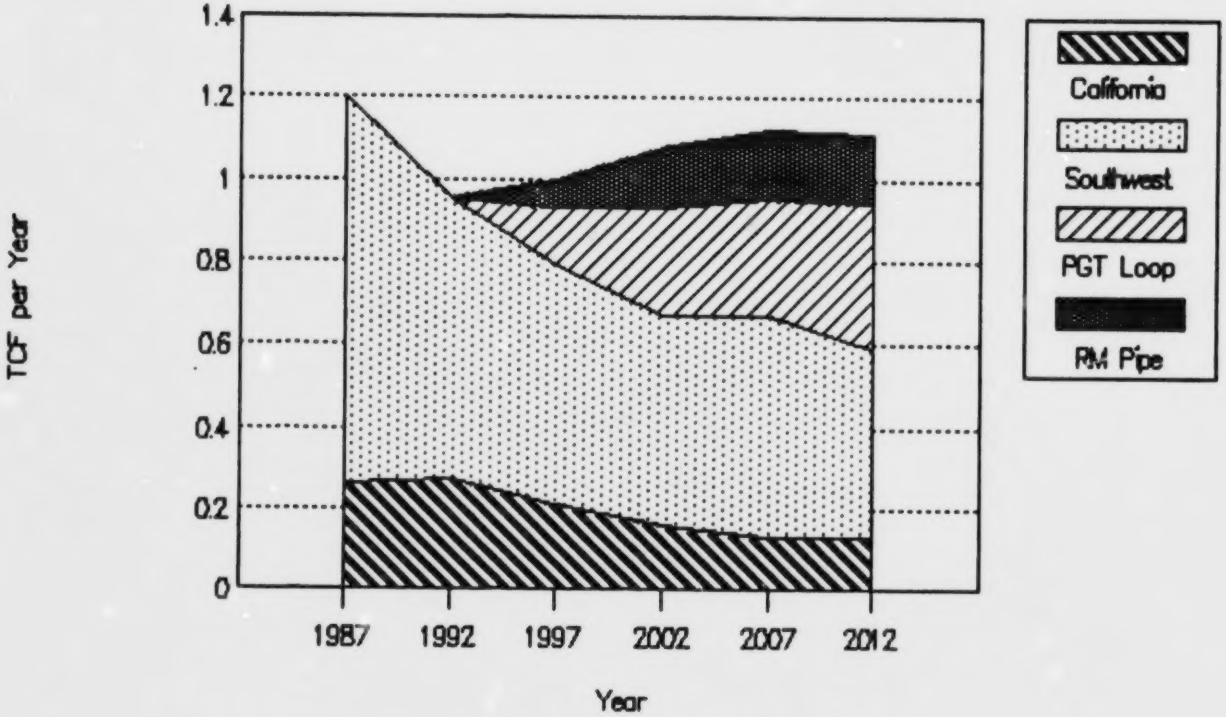
D. SOUTHERN CALIFORNIA SUPPLY

- Southwest continues to be largest source of gas.
  - Principally Coal Seam from San Juan Basin
- Canadian supply grows in importance.
  - Both B.C. and Alberta contribute to supply.
- Rocky Mountain Pipeline gas makes good penetration into Southern California Market.
- California production declines to about half of current production levels.

Figure 12

Southern California Supply

Preliminary ER 90



V CALIFORNIA EOR GAS AND OIL USE

FIGURE 13

A. SHOWS THE TOTAL GAS AND OIL NEEDS FOR EOR STEAMING

- Growth period from 1992 to 2002 then leveling off and reduction in fuel needs. (based on Biennial Fuels Report published in 1986)

FIGURE 14

B. SHOWS THE MULTITUDE OF GAS SOURCES AND OIL BURN

- California production direct sales declines.
- SoCal and PG&E sales/transport decline after Rocky Mountain and Mojave pipelines become operational.
- Rocky Mountain and Southwest Gas (Mojave Pipeline) are dominant sources of EOR gas supplies.

Note of Caution: Southwest supplies via Mojave, El Paso and Transwestern Pipelines are held up by Coal seam production which may be too optimistically brought into production by NARG.

Figure 13

Calif EOR Oil and Gas Use

Preliminary ER 90

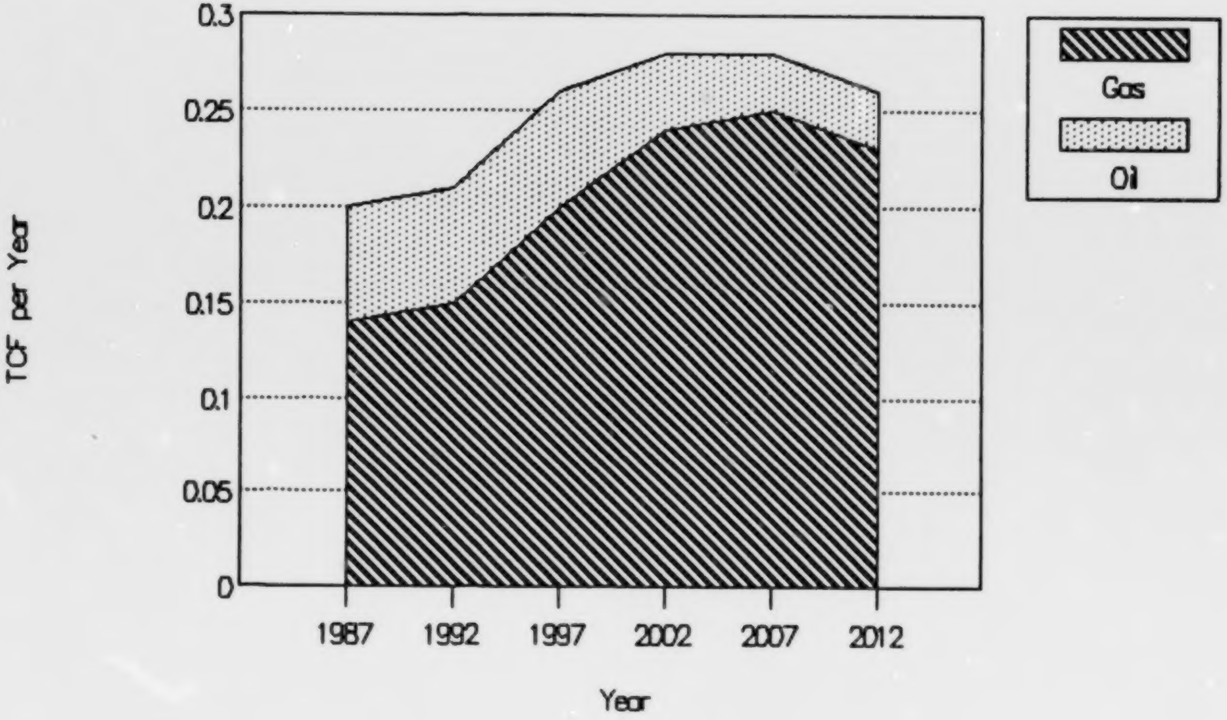
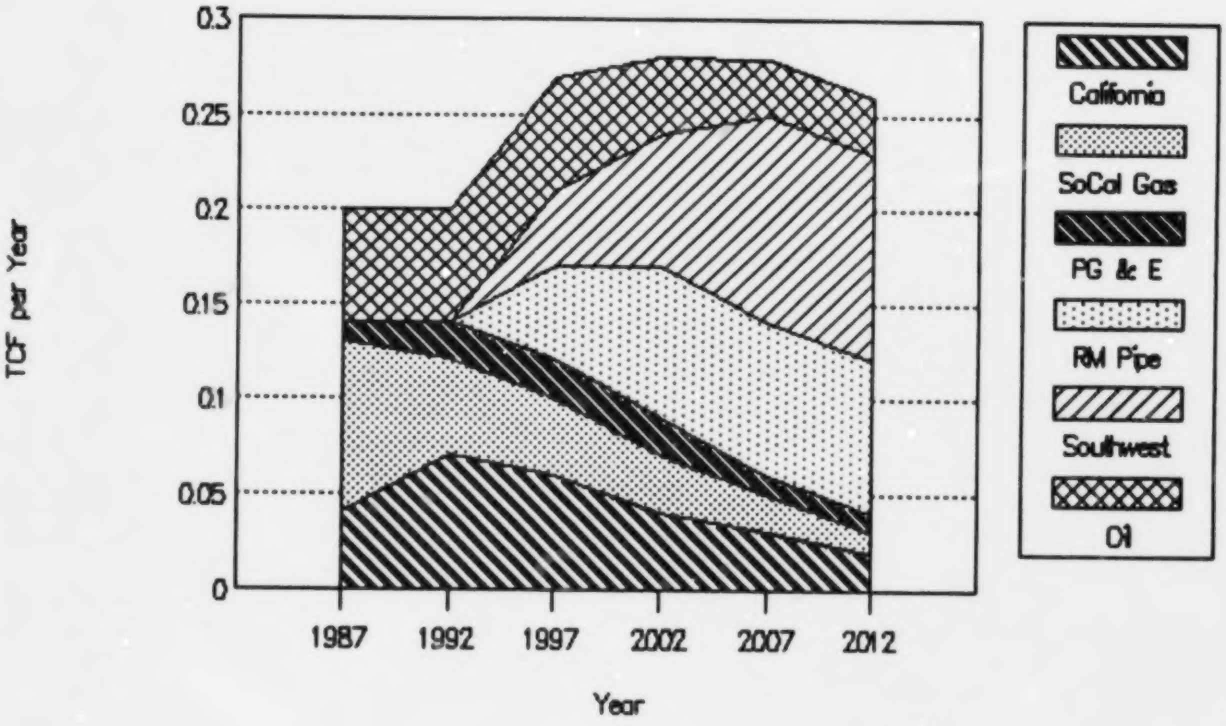


Figure 14

California EOR Gas & Oil Supply

Preliminary ER 90



"REGIONAL PIPELINE CONSTRAINTS AND DEVELOPMENTS"

Presented by

Mr. Frederick Duda
Commissioner
California Public Utilities Commission
San Francisco, California

EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

(Transcribed from a tape of Commissioner Duda's remarks.)

I have a great fondness for Canada and my visits here over the 39 years I've lived in California give me a great appreciation for Canada. You're our largest trading partner and your friendship means alot to us. We come here as your guests; we come reminded that you supply us with many good things.

California is a major industrial sector in the world. Our population continues to grow at approximately 750,000 people a year and is approaching 29 million. We have a very industrious economy; we are apparently the fifth or sixth largest economy in the world. We need many things to keep our people industrious and productive and one of these is an enormous amount of energy.

I'm here today to speak about a situation which has developed over the last 5 1/2 years, and remind you that it was on April 15, 1985, Mojave filed an application with the Federal Energy Regulatory Commission and sought, pursuant to Section 7C a Certificate of Public Convenience and Necessity, to construct and operate a pipeline extending from Arizona to the heavy oilfields in Kern County, California. A similarly proposed Section 7C application was filed by Kern River Gas Transmission Company. Kern River along with companion filings by El Paso Natural

Gas, Transwestern Pipeline and Northwest Pipeline were pending in a consolidated proceedings before FERC. On October 9, 1988 Mojave filed a second application with FERC for an optional expedited certificate under subpart E of Part 157, authorizing construction and operation of the same pipeline, and by FERC order dated May 8, 1989 Mojave has been granted a conditional certificate to construct its pipeline under the OEC Authority. The Wyoming/California Pipeline Company has also been granted an OEC by FERC. The proposed Mojave, Kern River and WYCAL projects are intended to serve primarily the incremental gas market associated with enhanced oil recovery of Kern County heavy oil production. Combined with the pending FERC application of PGT to expand its existing facilities from the U.S. border to the California/Oregon border, PG&E's proposed expansion is clearly intended to enhance its ability to serve all of the California markets.

What really is going on in our state? What really is going on concerning the relationship of the California market and our Canadian sources? Apparently there are small differences in the perception of the size of the market. That is quite clear from the three preliminary findings that Administrative Law Judge Barnett made on August 22 of this year. His first finding was, "I tentatively find there is a need for additional natural gas in California, which can only be met by the operation of a new interstate pipeline bringing gas to California". His finding number two was, "I tentatively find that the effect of assignment of firm gas transmission capacity rights will not negate or postpone the need for a new interstate pipeline". His third finding was, "I tentatively find that the effect of new capacity on the allocation of costs for existing capacity will cause either 1) additional demand charges on the current buyer who shifts from existing facilities to the new facilities if reallocation is not allowed, or 2) stranded investment on the existing pipeline if reallocation is allowed. I invite comments on this issue, especially directed to recommending a middle ground between full reallocation of demand charges and no reallocation".

Where are we now, and where are we going? We expect that Judge Barnett will submit to the Commission his proposed decision during the week of November 20. You may recall that in our December order we stated that we wished to pursue the question of new interstate natural gas pipeline capacity in a framework in which we set forth six objectives:

1) To ensure adequate, stable and reasonably priced supplies of gas to core customers.

2) To achieve access to a diverse pool of gas supplies so that we can achieve the first objective.

3) To reduce the likelihood of peak period curtailments by ensuring adequate, reasonably priced, reliable transmission access to non-core customers.

4) To obtain where economic, sufficient pipeline capacity to foster active gas-on-gas competition.

5) To avoid the negative impact of uneconomic bypass of local natural gas distribution systems.

6) To ensure that the costs of new capacity additions, as well as the costs of existing capacity from which new load may be displaced, are fairly allocated.

Following our enunciation of those six objectives, we proposed and expressed in the OII that we would consider new pipeline capacity additions under a matrix or framework of eight criteria:

1) Economic justification for new pipeline capacity.

We said that the amount of new pipeline capacity must be economically justified as a means of providing more reliable access to new long-term supplies to achieve among other benefits, cost reductions through gas-on-gas competition. And we said that new pipelines must be justified on the basis of the economics of total delivered cost of gas from each of the gas-producing regions.

2) Supply diversity.

We said that any new proposal for pipeline capacity should result in an interstate pipeline network which provides reliability of access to all producing areas.

3) Factor of capacity allocation.

We said that firm capacity on new interstate pipeline projects should be allocated in advance to California Public Utility Commission Regulated Utilities and their wholesale and UEG customers. And that some form of capacity brokering should be authorized on the new pipeline additions and capacity rights of enhanced oil recovery customers must be reallocated to the local distributing companies following termination of any EOR capacity contract. That recognized the forecast that the EOR usage would increase from 700 million a day to just under a bcf, and then plateau and decline over a time period.

4) Bypass issue.

We said that we continue to prefer that new interstate capacity should interconnect at the California state border with an intrastate pipeline subject to CPUC jurisdiction. Our support for settlements will depend on a commitment from any new pipeline that such dedicated FERC regulated EOR facility, shall not be expanded to bypass California LDCs to serve non-EOR customers.

5) Jurisdictional issue.

We said that while new EOR dedicated capacity may be federally regulated, after the period of time that such jurisdiction has elapsed, jurisdiction over such pipeline facilities constructed within the state must revert to the California Public Utility Commission jurisdiction.

6) EOR service issue.

We again expressed that following reversion of jurisdiction to the CPUC, and that EOR contracts for pipeline service will continue to be honored according to their terms of service.

7) Cost allocation issue.

We said that cost responsibility for new pipeline capacity must flow to those customers who will benefit from the firm service on the pipeline. We will not place risk of cost-recovery for such facilities on core-customers, except to the extent that it can be conclusively demonstrated that they benefit from the new facilities. The same principles will be applied to allocation of the cost of stranded investment in capacity.

8) Procedural issues.

We simply stated that certification, environmental review, rate design, and cost-allocation approvals will be conducted in the most expeditious manner possible.

At this point I'd like to refer to the substantial number of changes that have occurred in the proposals for new interstate pipeline additions. Not only have changes been proposed in the lines themselves, in the areas they may serve and connecting points, but also of course even in the constituency of the backers of such lines. Such changes are not surprising; however, it is a moving target for those who would see how these lines would impact our needs and our markets. Our Commission's Administrative Law Judge, Robert Barnett, is a capable gentleman who has a good understanding of the need for us to get on with this process. I mentioned the changes because they might suggest that delay is possible. But I don't think that is likely, or probable, although I speak to you as only one of five California Public Utility Commissioners and express only my own thoughts. I would believe the feeling at the Commission is that we definitely need to move forward with a decision in this case.

I won't review all of the changes that have occurred except to reflect that PGT continues to seek enlargement of its capacity. They continue to emphasize their producer commitment, their expansion benefits, including reliability of supply, and dedication and availability, competitive pricing, and their claim of being a least-cost project. I should certainly mention El Paso's current moves at the Federal Energy Regulatory Commission reflecting its collaboration with Kern River, upgrading its standing capacity on existing pipelines to accommodate the proposed 200 million a day expansion of the SOCAL gas system. And, there are other applications which would seek to increase their capacity by 600 million a day.

WYCAL's new filing makes substantial changes in their project including reduced total capacity to California, dropping the connection with El Paso NGS at Topok, Arizona, and proposing a more direct route to California with three alternatives. The flexibility is becoming mind-boggling because it's almost like a fast-track building of a nuclear plant. We seem to have the pipe being so flexible we can almost lay it anywhere, and move it at will. But they're proposing combinations to PG&E and SOCAL gas, also in two different splits, and they are proposing a final third possible split between PG&E and EOR market in Kern County, with their capacity now at 600 million a day.

I won't even discuss the calculations and forecasts of transportation prices. They appear to be very competitive now, even though the routes are considerably different. One would have to be realistic in terms of calculating how good the cost estimates are, and what the uncertainties are going to be in the building of the projects. The environmental concerns are there. All of the competitive aspects of the lines are reflected in statements by each sponsoring group concerning what they perceive their advantages to be, and answering the challenges of their competitors as to claimed or potential problems under each project.

Altamont, backed by the three leading Canadian gas producers Shell Canada Limited, Petro-Canada Inc., and Amoco with a combined production of over 700 bcf during the year 1988, and self-described as a long-term, secure gas supply, is impressive. It presents, the backers say, an integrated solution to California's gas needs and they describe their solution as containing supply diversification and optimization, competitive transportation, enhanced access to supply, and ensuring firm and continuing producer access. I'm now talking not about the original Carway to Bakersfield line that we heard about in February, but the Wildhorse to Opal, Wyoming connecting to Kern River in two phases: the initial phase using 200 million per day capacity in Kern River and the second, waiting to build the leg finally to full capacity from Wildhorse. Altamont continues to support its project to serve California's expanding market. It offers economies of scale, all achieved by combining access to U.S.-Rocky Mountain Overthrust belt gas and Western Canadian sources in one combined system. The 700 million a day capacity at a cost of about $580 million, a 620 mile line, is phased with 1991 capacity being utilized on Kern River and the 1993 commercial operating target date for the Wildhorse to Opal line.

What do these developments suggest for the decision that the California Public Utility Commission and the Federal Energy Regulatory Commission will be making? I won't suggest what the decisions will contain, but I certainly would reflect on several observations.

First, competition has stimulated innovation and resourcefulness and second, strategies have created unique projects that propose benefits that may have gone ignored or otherwise overlooked. Thinking has matured and careful planning has been accomplished. New alliances have been forged; a vision of the future has emerged and it is still emerging. Negotiations have created new windows of opportunity. Regulatory uncertainties may not have diminished, yet regulatory policies have changed or are changing. A policy decision or decisions should be made, or shall be made soon. Several things further are suggested.

The competitive market cannot decide matters that are properly regulatory policy responsibilities. Where true competition exists, monopoly and regulation should withdraw allowing the competitive market to do its efficient work. While markets cannot decide everything, market forces can cause, and rightfully should allow, the best of alternative, competitive projects to prevail, and in this case, meaning the building of a pipeline or a new interstate capacity. Costs of reserves, and costs of new additions to reserves most likely are a more important factor in the long run, in a least supply determination, than transportation costs. While I speak of win-win results, they are not only real and desirable, but they are in fact the logical outcome of carefully weighing risks and rewards and selecting for short-, mid- and long-term the benefits of the best project. Where competing projects have security of long-term supply, broad access for producer usage, regional diversity of supply basins, increased safety of supply protection against natural calamities, and probable continued short- to mid- and long-term least cost exploration and development and production costs, then it would appear to me today that gas producers, pipelines, developers and owners, bankers and financers, brokers, dealers and users both large and small, and governments, both state and federal, should recognize the substantial benefits from new capacity additions, and not delay unnecessarily their decision upon which line or lines to support. If the fact-gathering has been carefully completed, the assessment is underway, and clear analysis and comparison are possible, then resolute decision-making should be at hand. I believe it's time to decide and move forward into the future on this important matter.

Former members of my Commission may have adhered to a policy which favored cross-subsidization of certain segments of the end-user population in California. But you have a new Commission before you at this time, a Commission which has already enunciated and has selected its course in redesigning the natural gas industry and its regulation in California, which as recently as within the last 30 days issued a milestone telecommunications commission order completely revamping telecommunications regulation. It would appear likely that this Commission is both capable and willing to move forward with decision-making as it is needed and hopefully is foresightful enough to understand those things it must do to see that the vast California population and its major economy are served. I can't promise you a specific date, ladies and gentlemen, but I assure you that I for one will be aggressive and adamant that we must move forward with the decision this year.

THE 8TH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE

THE CONVENTION CENTRE
CALGARY, ALBERTA
OCTOBER 22-24, 1989

AN IROQUOIS UPDATE

Presented by:

ROBERT J. REID
President
Iroquois Gas Transmission System
Shelton, Connecticut

I. INTRODUCTION

- Good Morning, ladies and gentlemen. Its certainly a pleasure to be back in Calgary to provide you with an update on the Iroquois Project.

- If we were to turn the clock back by about a year, we would be roughly half-way through the Settlement process before Judge Wagner in Washington. Never before had there been an "Open Season"... it was a new experience for all of us.

- Though at times it was difficult to see a clear path through the process, we remained optimistic that a settlement could be achieved, and that the resultant projects could move through the regulatory process in an expeditious manner.

- I think you'll agree that the events of the past 12 months have proven that to be the case.

- South of the Border, our project is now well advanced at both the federal and state regulatory levels.

- And north of the border, this past summer's producer vote and subsequent rationalization of volumes has allowed the National Energy Board to set a definitive schedule for the review of the requisite facilities on TransCanada's system.

- The forces are finally with us and focussed on a common goal - final certification of the Iroquois project no later than next spring, which is consistent with a November 1991 in-service date.

- But although there has been a lot of water under the bridge, we have yet to realize our true objective--gas through the pipe! There is still a great deal of work to be done.

- This morning I intend to provide you with a brief summary of where we are, and where we are going.

II. THE IROQUOIS CONCEPT

- Iroquois is a successful project for one reason alone--it makes sense. Its market makes sense, its routing makes sense, and it is being implemented in a thorough and meticulous manner so as not to disturb the environment it will ultimately serve to protect.

- The Western Canadian Sedimentary Basin contains the largest, most secure gas supply in North America. Proven remaining reserves exceed 75 TCF, resulting in a current Reserves to Production ratio of over 27. Potential reserves are estimated to be in the range of 250-300 TCF.

- The northeastern United States is a market with the highest rate of growth in gas demand in North America, and an immediate need for incremental quantities of gas. In fact, this market has grown by more than 34% during the past 12 years, while the U.S., as a whole, actually experienced a decline during the same period.

- Iroquois provides the missing 370-mile link between North America's largest, most secure gas supply and its' largest, fastest-growing market.

- In conjunction with our partner, Tennessee Gas Pipeline, Iroquois will serve 20 customers in New England, New York and New Jersey. Eighty-eight percent of our volumes are destined for LDC's, with the remaining 12% for cogeneration or power generation projects. Gas deliveries will be split roughly 50% to New England and 50% to New York/New Jersey markets.

III. PROGRESS AT THE FERC

- On May 2, the FERC issued an order confirming that the Iroquois, Champlain, and ANR projects were discrete--that is free to move forward independently on their own schedules in accordance with their individual merits.

- Also on that date, FERC terminated all remaining open season dockets--there are no remaining alternatives on file at the FERC contemplating incremental service to the Northeast.

- The FERC are now focussing their attention on the three primary subject areas that constitute an application to construct pipeline facilities under Section 7 of the Natural Gas Act: Need, rates, and the environment.

- It is the environmental review process that will clearly drive FERC's regulatory timetable for our project. Earlier this year, FERC established a firm schedule for this review that contemplated a Draft Environmental Impact Statement (DEIS) being issued this fall, with a Final Environmental Impact Statement (FEIS) issued next spring.

- At a recent meeting in Boston, a senior member of FERC's staff confirmed that they are "on schedule, and intend to stay that way". Our DEIS is expected to be issued approximately two weeks from now--on November 8.

- Recognizing the importance of the environmental review process, we have implemented a full program of field activities to ensure that FERC has all of the site-specific data it needs to adhere to its schedule. Included in this program is an extensive cultural resources survey, soil and water evaluations, biological survey of threatened and endangered species, and an assessment of wetlands and stream crossings.

- Since May 2, we have responded to over 100 detailed data requests from the FERC environmental staff, and have submitted revised and updated maps to a standard scale and format for the entire route.

- FERC staff and their environmental contractor have viewed the entire route from the air several times, and have walked key line segments.

- I can assure you that the environmental evaluation of our route is being conducted in a thorough and meticulous manner. I am not aware of any requirement imposed by FERC environmental staff which has not been met satisfactorily by Iroquois.

- With respect to need, Iroquois has responded fully to FERC's June 22 Market Data Request. The record on need and markets is now fully up to date for all Iroquois' shippers, demonstrating in a quantitative manner the clear need for the additional natural gas supplies and pipeline capacity. Iroquois' market data has already successfully withstood the scrutiny of detailed evidentiary examination before the New York State Public Service Commission.

- With respect to the third area - rates - Iroquois has requested a technical conference which would serve to identify and resolve any outstanding rate issues. It is my understanding that FERC will schedule this conference in November

- The bottom line on FERC is that they are proceeding on a schedule which will permit a November 1991 start-up for our project.

IV. STATE REGULATORY PROGRESS

- I would now like to briefly review the progress of our project at the state level.

- For over two years, we have participated in a New York State Public Service Commission Article VII proceeding on environmental compatibility and public need. This is New York's so-called one-stop shopping process for all of the environmental permits required to construct a pipeline in that State. It has been a lengthy and very detailed proceeding.

- I am very pleased to report that on October 4, the Commission approved the construction of our pipeline in that State. Their decision solidly endorses the public need for our project, and finds all considered alternatives to be environmentally and economically inferior.

- Receipt of our Article VII Certificate means that we now have full state approval for over 80% of our route.

- In Connecticut, the CSC has confirmed that its jurisdiction over Iroquois is residual to that of the FERC. This means that although they cannot commence their review until a FERC Certificate has been issued, they cannot act in a manner that is inconsistent with it.

- The CSC plans on dealing with location specific issues of pipeline alignment and environmental mitigation, plus issuance of local permits.

- In anticipation, Iroquois is working with the cities, towns, land trusts and landowners along the 48 mile route in Connecticut to resolve as many of these issues as possible.

- We are also working with the Connecticut Department of Environmental Protection, from which we need both coastal zone consistency and Clean Water Act certifications. Neither of these is anticipated to be a problem.

- Again, we view the State processes as proceeding on a schedule consistent with a November 1991 in-service date.

V. THE CANADIAN SCENE

- I'd like to now turn North of the border, and focus on the recent producer vote and the Canadian regulatory timetable.

- Last August, Western Canadian producers rendered decisions on many different contracts representing gas earmarked for the northeastern U. S. market. As I indicated earlier, over 80% of the gas supply for the Iroquois project was subject to last August's vote.

- We are extremely pleased with the outcome. The producers approved sales to Alberta Northeast Gas, Limited--the marketing organization representing 16 of our LDC's. ProGas producers also approved sales of 25 MMcf/d to the Masspower project in Massachusetts.

- However, the producers rejected contracts for two of our cogeneration customers--L & J Energy Systems in upstate New York and First Energy Associates in Connecticut--totalling 24.7 MMcfd.

- In my view, rejection of these cogeneration contracts should not be interpreted as staunch producer opposition to the concept of gas-fired power generation, but rather rejection of the specific contractual terms themselves. Remember, the Masspower contract was approved by the producers. Future cogeneration and combined-cycle power generation projects undoubtedly will be served by Canadian natural gas given the right contractual terms and circumstances.

- TransCanada Pipelines' application to the National Energy Board for facilities north of the border can now be amended, culling out those shippers who fail to meet TCPL's "Supply Assurances" criteria.

- As many of you are aware, The NEB are currently re-evaluating the appropriateness of TCPL's Gas Supply Assurances criteria by means of a written hearing--GHW-3-89. I understand that a decision is expected on November 6.

- On September 25, the NEB issued a hearing order for TCPL's 1991/92 facilities, together with an illustrative schedule for the proceeding, that envisages a hearing early in the New Year, and a decision by the end of June 1990.

VI. SHIPPER STATUS

- As I noted earlier, we have had some changes in the identity of our shippers, and, as a consequence, some changes in volumes and the geographical distribution of our load.

- These changes all stem from the Canadian side of the border. A total of five Iroquois shippers--all cogenerators or power producers--failed to meet TransCanada's "Supply Assurances" clause--as it now stands--and have had their precedent agreements for transportation terminated by TCPL. These five shippers represented a total of 74.1 MMcf/d (14%).

- Two of the five shippers had their supply contracts rejected by the Alberta producers, while the other three shippers failed to meet TransCanada's "Supply Assurance" requirements for other reasons.

- Following August 11, when TransCanada confirmed the loss of the five shippers, two of our existing customers requested an increase in their volumes. On September 15, Granite State and Iroquois agreed to amend their precedent agreement to increase Granite State's transportation volumes from 12 MMcf/d to 35 MMcf/d. The supplier is Shell Canada. On September 18, Boston Gas and Iroquois agreed to amend their precedent agreement to increase Boston Gas' transportation volumes from 17.1 MMcf/d to 52.1 MMcf/d. The additional 35 MMcf/d is supplied by Esso.

- Recognizing that these additional volumes are volumes formerly proposed for shipment on the Champlain system, we have been very careful to ensure that the Principles of Settlement are not violated. Our agreements to add these new volumes are expressly conditioned on the validity of Granite State's and Boston Gas' notices terminating their transportation arrangements with Champlain, so that these shippers are free and clear of all legal obligations to the Champlain project.

- Our agreements to add these volumes are also conditioned upon the absence of a FERC determination that the proposed service is "competitive" with another project. If the FERC were to determine that provision of this additional service would render Iroquois "competitive" with another project, our agreement to provide the additional service self-destructs.

- Our "belt and braces" approach here assures that provision of additional service to these customers will not violate the November 30 Principles of Settlement.

- As a result of these changes, our total firm contracted volume now stands at 517.8 Mdth/d. We have committed to the FERC that we will not increase our facilities beyond those applied for last January, in order to keep the environmental review for our project on schedule.

VII. CONCLUSIONS

- As I indicated at the outset, we have come a long way in the past twelve months. With a positive decision from the producers in August and another from the State of New York earlier this month, we are finally moving out of the hearing room and onto the right of way--concentrating on the detailed environmental and engineering aspects of our project.

- We are right on target, and look forward to providing the Northeast with a new, long-term, secure supply of Western Canadian natural gas--the environmental fuel of preference for the 1990s

REGIONS WITH HIGH GROWTH POTENTIAL

Presented by

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EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

ABSTRACT

Growth in the future will not be restricted to booms in frontier areas, but will also be as a result of more efficient exploitation of late life reserves and new fiscal incentives in established areas. In a background over the past year of concerns over price, tempered with a degree of optimism amongst the reduced numbers of independent companies that survived the 1986 low, the industry as a whole has re-examined its perspective. Alongside ROR considerations, companies are examining land positions, tax and exposure levels with resultant portfolios balanced by both frontier and mature holdings and all with a more confident view of the future.

In Asia Pacific, drilling activity has followed price fluctuations but is currently at respectable levels, split between such established countries as Indonesia, India, and the newer players: Vietnam, PNG and Nepal. With countries such as Malaysia awarding a series of new production sharing contracts, we can expect to see substantial new activity in the 1990s. Australia, like much of the rest of the region, is re-evaluating its fiscal incentives.

African levels of activity continue, in the search to find further large discoveries, with acreage promotion at a high, particularly West African countries such as Angola and Gabon. Much of the area remains a high risk but high reward region, increasingly attractive if drilling costs could be further reduced.

Latin America is a region which brings to mind problems of legislative instability and large international debt burdens, while good geological prospectivity does not catch the headlines. But on closer inspection, the continent today displays a new stability, and by comparison its debt burden is less severe than one imagines. In this new mood, one could highlight for re-examination Basins in Peru, Bolivia and Argentina.

Many U.S. concerns are looking internationally. Does this itself suggest it is perhaps a time to re-examine their home ground? There are certainly new opportunities in gas. That holds true for the U.K. where activity remains at peak levels both in oil and gas, and there appears to be no significant drop in the size of fields currently being discovered.

Perhaps the most worrying concern remains the continued assessment of our business on the basis of quarterly cash performance under the eyes of a worldwide community of analysts, who rarely now have anything more than short term perspectives. In this context it is difficult to see how even the largest company will be able to take the long term decisions necessary for their medium and longer term good.

Indeed some of the moves towards cash management appear to suggest that some companies will ultimately leave the industry altogether in favour of managing the cash from the ultimate sale of their assets.

The implications of this approach already show themselves in exploration as we seek to quantify the ultimate potential of imaginative ideas which have not yet received even the benefit of preliminary assessment. Learning to deal with this new view of our business is one of the challenges of the immediate future.

The World is different now. Activity in hotspot frontier areas is being balanced by better management of mature provinces, and we are maximising our tax efficiency while pushing costs down. Yes, the next decade will see new hotspots but the majority of drilling and exploration will be in the areas we already know at least something about. That balance will ensure that future growth will be more widely spread than previously, and means that if one of our exploration dreams turns out to be a nightmare, we are well protected elsewhere.

October 1989

COLOMBIAN PERSPECTIVE IN THE PETROLEUM INDUSTRY

PRESENTED BY

ENRIQUE AMOROCHO

EIGHTH CERI INTERNATIONAL OIL

AND

GAS MARKETS CONFERENCE

CALGARY, ALBERTA

OCTOBER 22--24, 1989

CONTENTS

. COLOMBIA

. OIL INDUSTRY IN COLOMBIA

. CONTRACT SYSTEMS

. INTERNATIONAL TRADE

. ECOPETROL´S YEAR 2000 PLAN

. TRANSPORTATION

. WHITE PRODUCTS CONSUMPTION

. CONSTRUCTION OF A NEW REFINERY

. NATURAL GAS

. RESEARCH AND TECHNOLOGICAL DEVELOPMENT

. GLOBAL BALANCE

COLOMBIA

Colombia is located on the northwestern end of South America. It has the Atlantic Ocean to the north and the Pacific Ocean to the west and borders with Panama. Venezuela. Brazil. Ecuador and Peru.

Both the geopolitical location of Colombia and access by two oceans make Colombia a country of advantageous position favouring trading possibilities with Europe to the northeast and China. Japan and Taiwan to the west.

The Colombian continental territory has an extension of 1.142.000 kms^2. Its Caribbean coast on the north is 1.600 kms long and the Pacific on the west is 1.300 kms. in length. 71.5 million hectars of the country are sedimentary basins.

Population is over 30 million inhabitants with annual income per capita of US$1200. The actual energy consumption is 512 thousand barrels per day of equivalent crude oil with a participation of 45% of crude oil and 15% of natural gas.

OIL INDUSTRY IN COLOMBIA

Exploration started in Colombia at the turn of this century. The concession agreement system lasted until 1974. Exploration averaged 10 wells per year until the early 50's. In 1951 ECOPETROL was founded by the Colombian government, with the reversion of De Mares Concession in the center of the country. During the late 50's, 60's and early 70's, exploration increased to an average 30 wells per year. In 1969 Law 20 establishes the preliminary conditions for major participation of ECOPETROL, which 5 years later, developed into what is now known as the Association Contract System. After 1980 production gradually began climbing and exploration went from 27 wells drilled in that year to 87 in 1988. In 1983 the Caño Limón field was discovered, adding about 1.2 billion barrels of crude to the country's reserves.

Direct operation started with the creation of Empresa Colombiana de Petróleos, ECOPETROL, a state-owned enterprise with concerns in oil and gas production and trade which operates under the Ministry of Mines and Energy. It is in charge of research, exploration, development, transportation, refining, and trading of crude and products. ECOPETROL is also responsible for supply of fuels and derivatives within the country. The company currently employs 12,000 direct workers and 50,000 indirect people.

CONTRACT SYSTEMS

1. CONCESSION

The Concession contract between the Colombian government and a private company, was the first approach established in the country for exploration and exploitation of hydrocarbons. This system was abolished in 1974. Concessions existing at that time were not affected, as they remain valid until they run out and once again revert to the Colombian state.

Some of these concessions are still in force and in those areas both exploration and exploitation have been carried out by different foreign companies. In return the company pays the government royalties on gross production, which fluctuates between 7.5 and 14.5%.

2. ASSOCIATED OPERATION

The Association Contract is the actual system in Colombia for exploration and further exploitation through association between private capital, either foreign of national, and Empresa Colombiana de Petróleos.

The basic aspects of this contracting system are the following:

- An initial exploration period of 3 years which may be extended up to 6 years, and 22 years as an exploitation period as of the date of termination of the exploration period.

- During the exploration period, the investment risk is assumed totaly by the associate, in accordance with a schedule previously agreed upon with ECOPETROL. This schedule generally carries out surface exploration and drilling of wildcats. ECOPETROL provides the associate with all available information on the contracted area.

- There is a program of restitution of areas under the contract, according with the different periods up to it is limited to that of the field under exploitation, plus a protection zone of 5 kms in width, 4 years after end exploration period.

- ECOPETROL's share in the total production is 60%, including 20% of royalties. The remaing 40% is held by the Associate which may sell it to ECOPETROL at international price, or exported it if the country doesn't need it.

- ECOPETROL participates with 50% of the investment and production costs.

The Association Contract has been of great importance for exploratory activity in Colombia. In 1989, for the first time, the number of Association Contracts reached over 100. Out of the total of remaining reserves to date, (2.2 billion of barrels as proven reserves) about 70% are owned by ECOPETROL, including those with right to share in the Association Contracts. Associates have 590 million barrels under those contracts. Associated Operations contribute with 65% of the total production.

3. RISK PARTICIPATION

Recently, ECOPETROL implemented a variation of the Association Contract called RISK PARTICIPATION CONTRACT, by which the state company gives some of its reserved areas to the associate, and ECOPETROL participates in 15% of the investments in drilling as of the second exploratory well or third year of the contract, and in exchange, our company obtains a higher share of the production as compared to the standard Association Contract.

OTHER INNOVATIONS

Currently, the Colombian government is studying establishment of several modifications in the Association Contract (Standard and Risk Form) in order to update the system. Among these are: increased share in the Standard Contract, as certain production ceilings are reached; within the application of technological transfer involved in the contract; ecological control; and control mechanisms for the assignment of total or partial transfer of the contract rights to third parties.

INTERNATIONAL TRADE

Up to 1974 Colombia exported crude but due to a decline in exploration and reserves became an importing country as of that year. This situation lasted until 1986. By that time Caño Limón had been discovered and the country recovered its position as an exporter on international markets. Currently the country produces around 430,000 barrels of crude per day, of which 240,000 are used for domestic consumption, leaving 190,000 for export by ECOPETROL and several associates.

ECOPETROL'S YEAR 2000 PLAN

Colombian government stablished as a target to mantain its position as a net exporter of crude oil. For this purpose, in 1988 ECOPETROL's designed a plan called "ECOPETROL'S YEAR 2000 PLAN" which basically consists on the give the first priority to the exploration activities. This plan hopes to descover 1.3 billion barrels as proven reserves, in crude, and 1070 GSCF in natural gas.

It is estimated that for this purpose 155,000 kilometers of seismic lines must be necessary to be run and 945 new wildcats must be drilled, in the different 13 sedimentary basins. The total estimated investments, in these activities, is of 2.5 billion U.S. dollars

For the total exploratory activities, ECOPETROL hopes to share 30% and the associates companies the remain 70% through the association standard and risk contracts.

TRANSPORTATION

Current transportation networks cover 4500 kilometers in different directions of the country. New oil fields have made an expansion of present facilities necessary, along the following stretches:

- CAÑO LIMON-COVEÑAS PIPELINE

  This 24 inche pipeline runs 800 kms from the Caño Limón field directly to the Caribbean coast, ending in Coveñas, a seaport on the Caribbean, where a Floating Storage Unit of 2.2 million barrels in capacity is anchored a few miles offshore. This line, completed by the end of 1985, handles 225,000 B/D of Caño Limón crude for exportation.

- LLANOS CENTRAL PIPELINE

  This line stretches 510 kms using 20 and 24 inch pipe, and carries crude from the area of Los Llanos to the central region of the country, with an initial capacity of 75,000 B/D.

- COLOMBIA PIPELINE

  A new pipeline is already underway, stretching 900 kms with an initial capacity of 150,000 barrels per day. This pipeline will service the central part of the country, coming from the high Magdalena Valley basin conecting with Llanos Central Pipeline, and going to the port of Coveñas.

  This system is divided in two stretches. The first one is been constructed by associates and the other one, by a company in which ECOPETROL shares 49% and the remain 51% by associates with actual production in the area.

WHITE PRODUCTS CONSUMPTION

White products include a variety of gasolines and medium distillates.

Motor gasoline has a consumption of 100,000 barrels per day, with an annual growth rate of 5%

Among medium distillates, diesel has the highest consumption with 35,000 B/day and an annual growth of 4%

Actual refining capacity of the country is 214 Thousand barrels per day with some expansion of one of the two main refineries in the country, next year total refinery capacity will be reach 244 thousand barrels per day. Considering the domestic demand, in 1990 it will be necessary to import an average of 20 thousand barrels per day of motor gasoline, but the country will continue exporting 60 thousand barrels per day of Fuel Oil number 6..

CONSTRUCTION OF A NEW REFINERY

The government is studying a project for a new 75,000 b/d refinery which should start operations in 1995. This would be a Mid-Conversion Refinery with the following processes:

- Atmospheric and vaccuum Distillation
- Visbreaker
- Fluid Catalytic Cracking
- Polymerization
- Utilities and OMS facilities

NATURAL GAS

Colombia has around 4 trillion SCF of natural gas reserves, of which 80% correspond to the Guajira fields on the Caribbean coast. These fields are of non associated gas with a potencial of production of 450 million standard cubic feet per day and an actual production of only 230 million SCF/D.

Current total demand is around 400 million cubic feet per day, half going to the thermoelectric utility companies. ECOPETROL is thinking about massifying use of this product in residential areas, and as compresed natural gas. Colombia is looking for new industrial projects which converts natural gas in more valuable products.

RESEARCH AND TECHNOLOGICAL DEVELOPMENT

Research and technological development activities are seen as a vital factor and as the basis for a more efficient performance of ECOPETROL'S activities and of the petroleum industry in the country as a whole.

ECOPETROL created the Colombian Petroleum Institute (ICP) in 1985, whose headquarters are in Bucaramanga. The institute carries out the following objectives:

- Applied research with the view of acquiring new scientific and technological knowledge in order to optimize upstream and downstream activities.

- Development of new products equipment, processes and approaches for the oil and petrochemical industry.

- Technical operational services and other specialized services.

- A more significant participation of Colombian industry in the supply of material, equipment and high-quality chemical products.

GLOBAL BALANCE

As you have seen, Colombia has elaborated an exploration plan to maintain its present self-suficiency capacity.

The exportation of crude oil could be increased for the year 1991, when we have finished the construction of the pipelines. However, the volume exported will be decreased by 1995, when the new refinery begin operation.

ATTACHMENT

COLOMBIA
ECONOMIC INDICATORS

● **POPULATION:**	30 MILLION INHABITANTS
● **AREA:**	1,142,000 KM2
● **COASTLINE:**	
ATLANTIC	1600 Km
PACIFIC	1300 Km

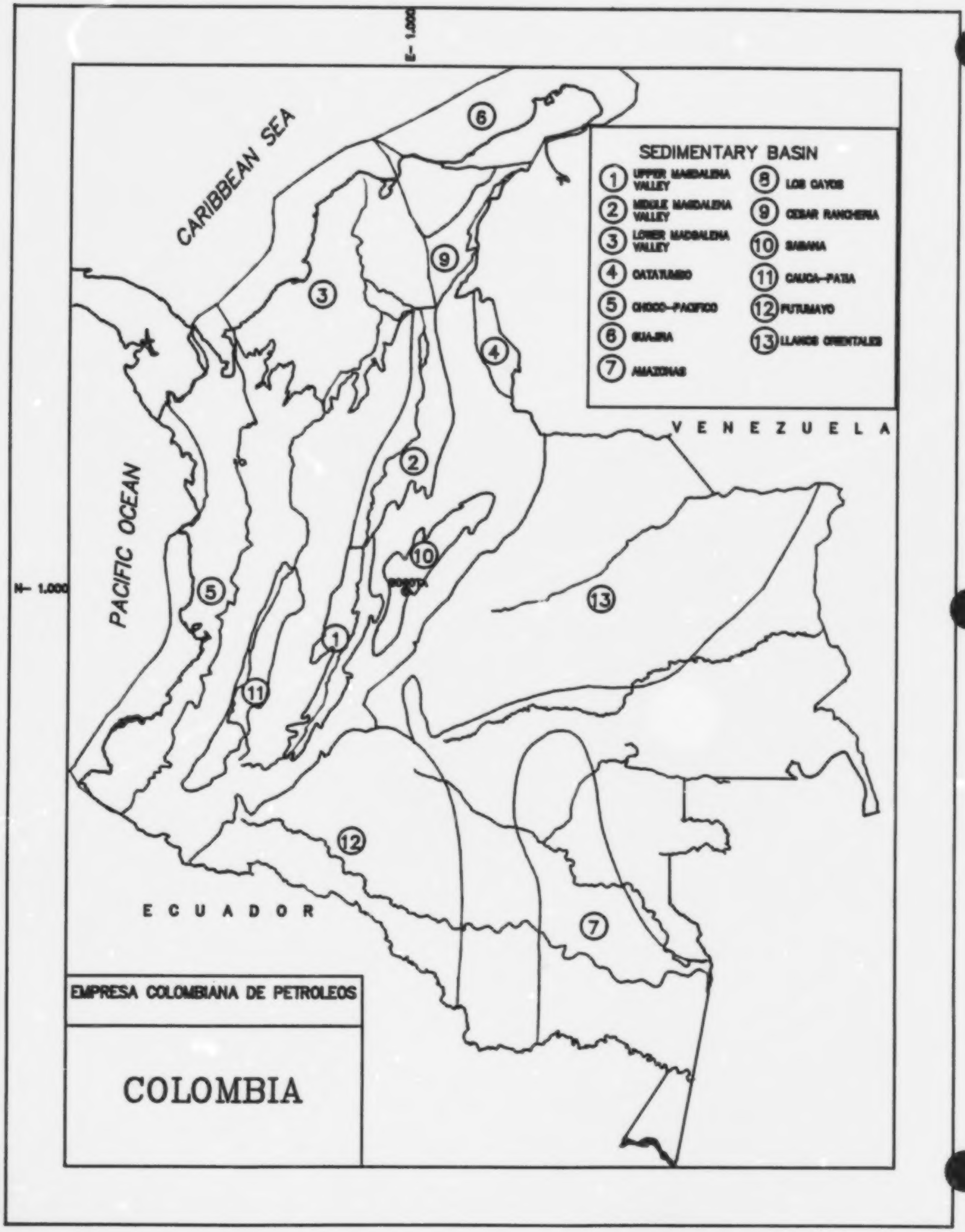
COLOMBIA
ECONOMIC INDICATORS

● AVERAGE YEARLY INFLATION	28.0
● AVERAGE YEARLY DEVALUATION	27.0
● UNEMPLOYMENT RATE	10.3
● GDP GROWTH	3.7
● GDP PER CAPITA (US $ / YEAR)	1200.0

FOREIGN TRADE

(MUS $)

	1988	1989	(%)
● **EXPORT**			
● COFFEE	1605	1690	5,3
● OIL AND DERIVATIVES	939	1137	21,1
● COAL	337	435	29,1
● NICKEL	180	146	(23,3)
● GOLD	405	413	2,0
● OTHERS	1821	2040	12,0
TOTAL	5287	5851	10,7
● **IMPORT**			
TOTAL	(4384)	(4785)	9,1


E- 1.000
N- 1.000
CARIBBEAN SEA
PACIFIC OCEAN
VENEZUELA
ECUADOR
BOGOTA
SEDIMENTARY BASIN
① UPPER MAGDALENA VALLEY
② MIDDLE MAGDALENA VALLEY
③ LOWER MAGDALENA VALLEY
④ CATATUMBO
⑤ CHOCO–PACIFICO
⑥ GUAJIRA
⑦ AMAZONAS
⑧ LOS CAYOS
⑨ CESAR RANCHERIA
⑩ SABANA
⑪ CAUCA–PATIA
⑫ PUTUMAYO
⑬ LLANOS ORIENTALES
①
②
③
④
⑤
⑥
⑦
⑨
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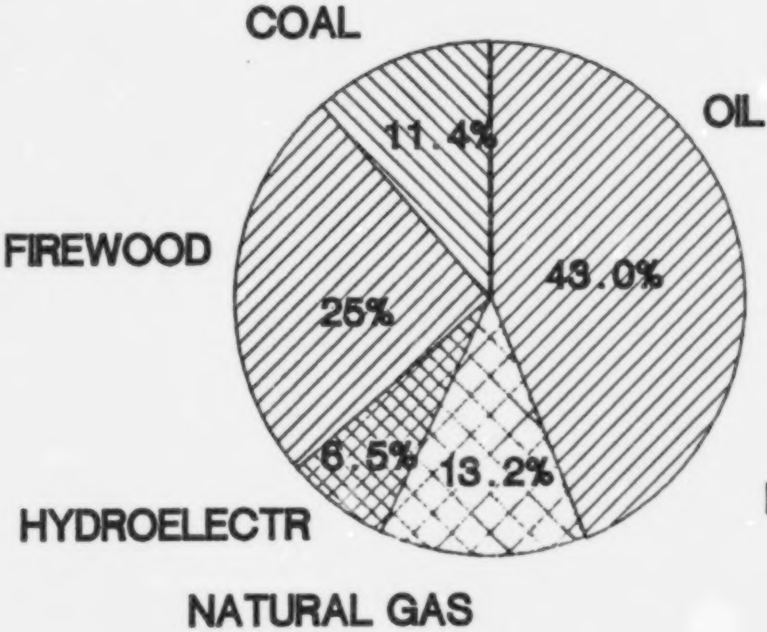
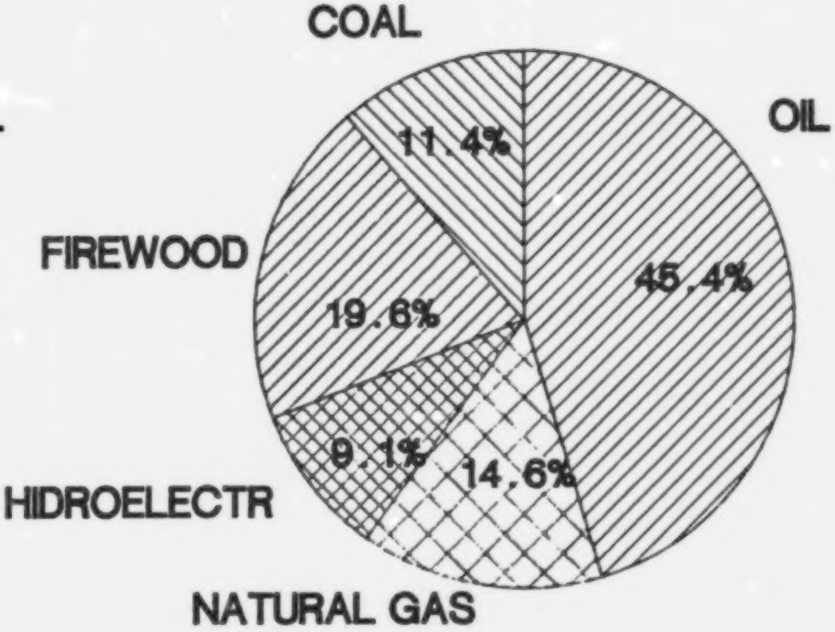
⑫
⑬
EMPRESA COLOMBIANA DE PETROLEOS
COLOMBIA

ENERGY IN COLOMBIA
ENERGY CONSUMPTION



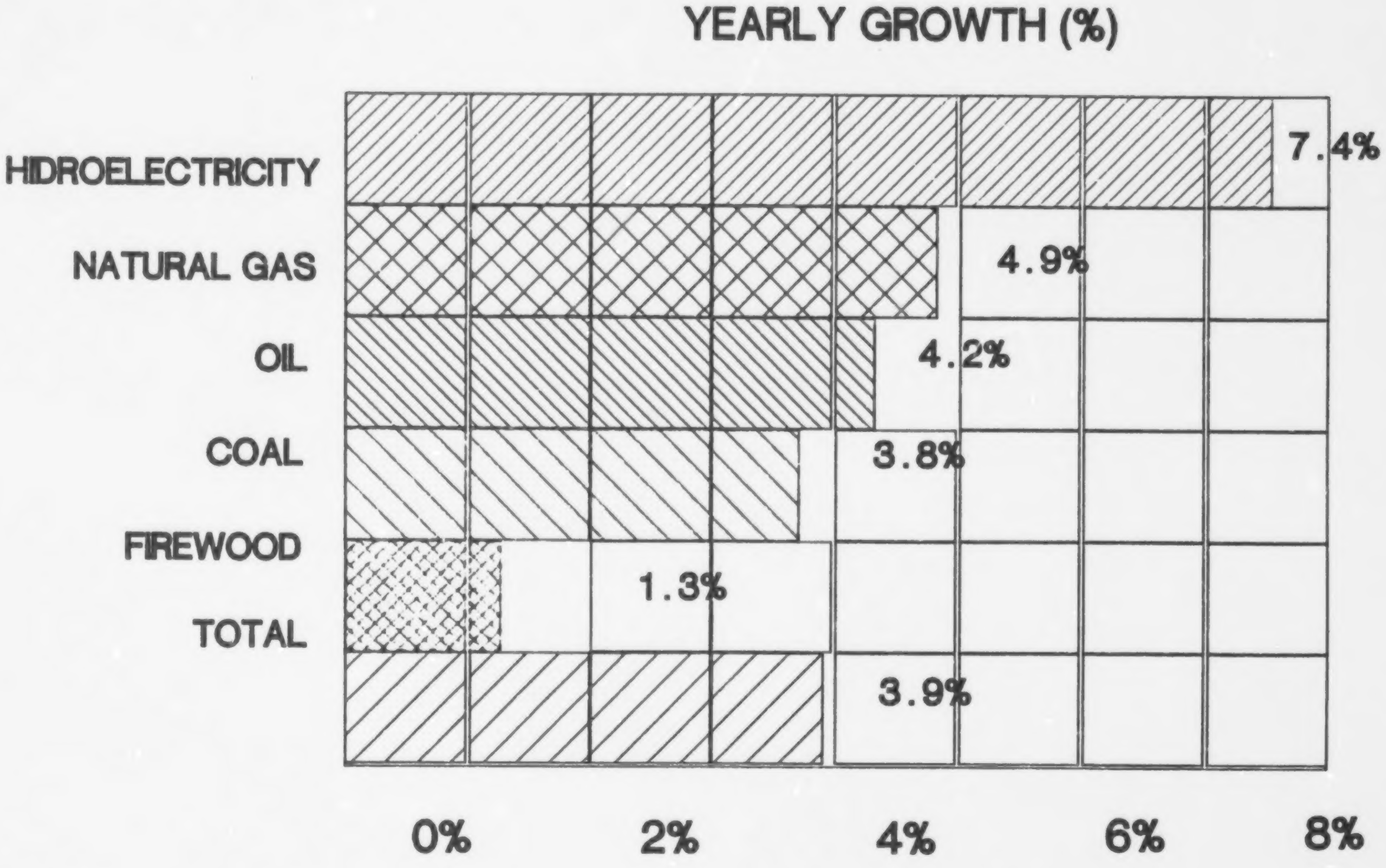
1978

TOTAL 349 OIL EQUIVALENT KBPD

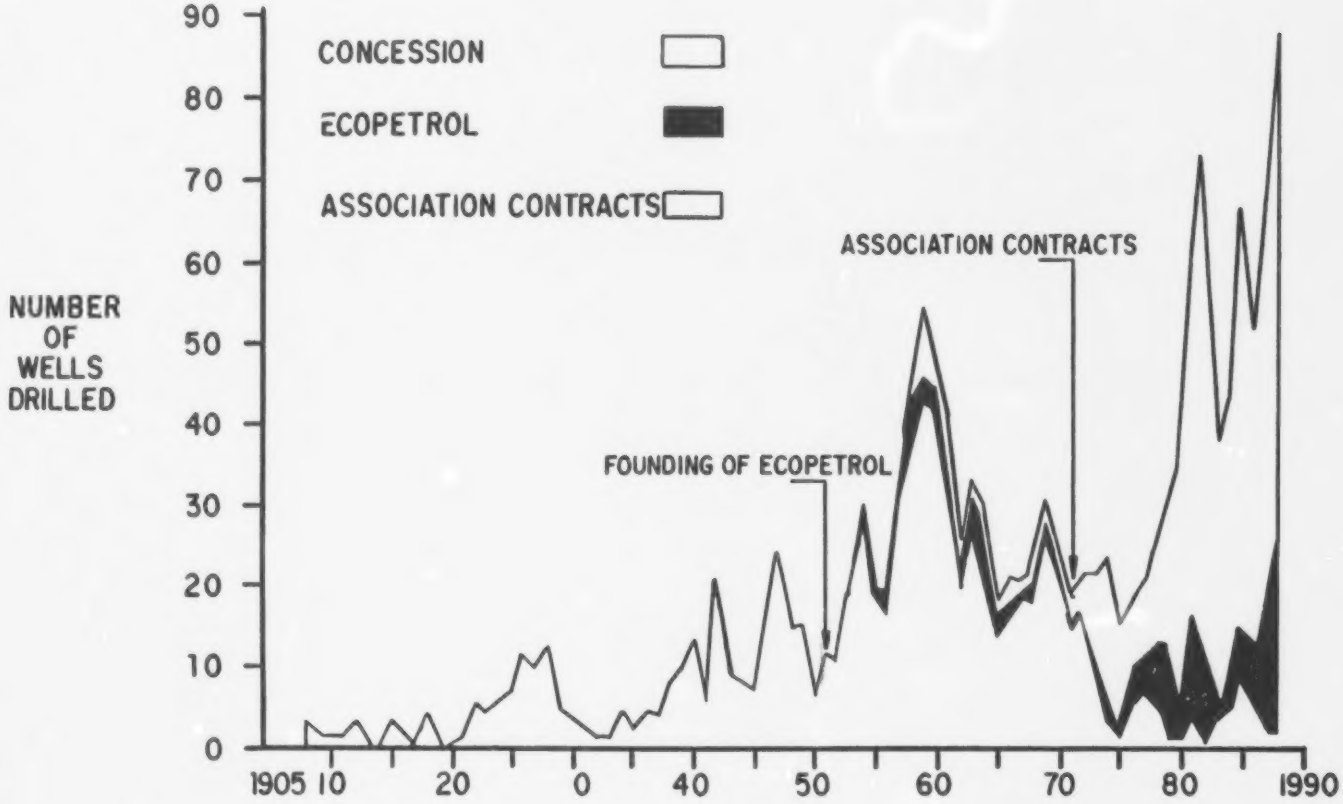


1988

TOTAL 512 OIL EQUIVALENT KBPD


YEARLY GROWTH (%)
HIDROELECTRICITY
NATURAL GAS
OIL
COAL
FIREWOOD
TOTAL
7.4%
4.9%
4.2%
3.8%
1.3%
3.9%
0%
2%
4%
6%
8%

WILDCATS IN THE COUNTRY



ECOPETROL

ECOPETROL IS A STATE - OWNED ENTERPRISE WITH CONCERNS IN OIL AND GAS PRODUCTION AND TRADE, OPERATING UNDER THE JURISDICTION OF THE COLOMBIAN MINISTRY OF MINES AND ENERGY.

ECOPETROL HANDLES THE FOLLOWING OPERATIONS:

- EXPLORATION
- EXPLOITATION
- TRANSPORTATION
- REFINING
- TRADING
- RESEARCH

ECOPETROL BEGAN OPERATIONS ON AUGUST 25, 1951.

CURRENTLY EMPLOYS:

- 12,000 DIRECT AND
- 50,000 INDIRECT WORKERS

EXPLORATORY ACHIEVEMENTS

	ECOPETROL	ASSOCIATION	CONCESSION	TOTAL
● SUPERFICIAL EXPLORATION				
Kms . of Seismic	60,000	100,000	40,000	200,000
● EXPLORATORY DRILLING				
Number of Wells	113	403	563	1,079

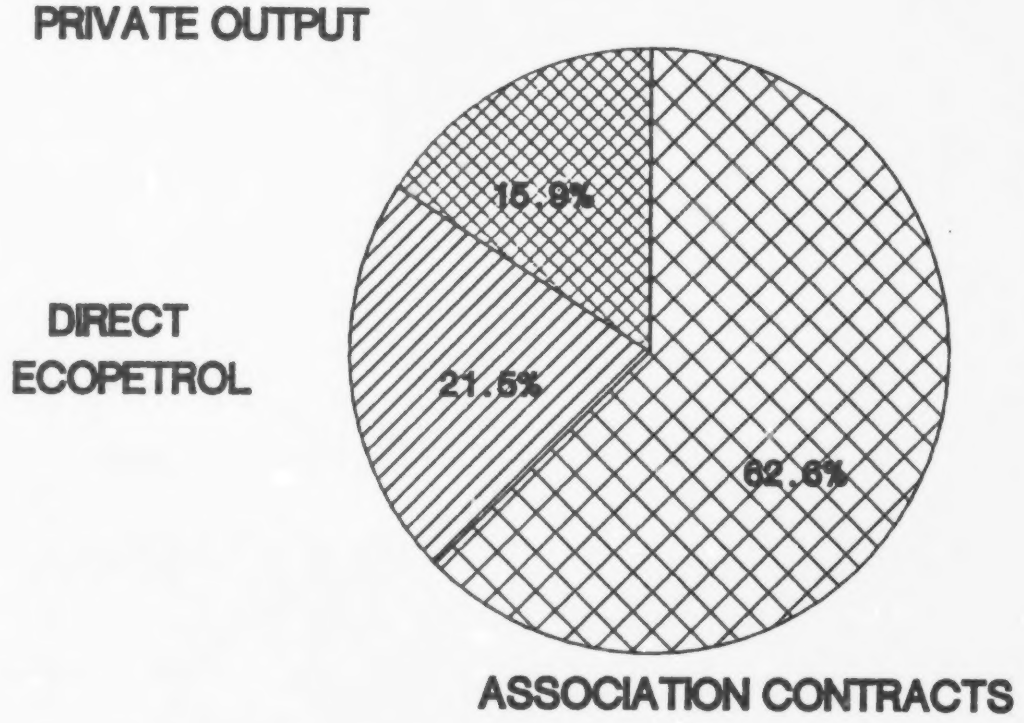
EXPLORATORY ACHIEVEMENTS

	ECOPETROL	ASSOCIATION	CONCESSION	TOTAL
● OIL RESERVES (MBls)				
Discovered	2,518	1,826	745	5,089
Remaining	605	1,471	120	2,196
● GAS RESERVES (CFG)				
Discovered	2,413	5,155	1,484	9,054
Remaining	661	3,831	166	4,658
● INVESTMENT IN EXPLORATION				
Million dollars	400	1,700	1,400	3,500

EXPLORATORY COVERAGE IN BASINS

	Sedimentary Area Km 2	Total Wells A-3	Coverage Km2/Well
● ACTIVE BASIN			
TOTAL BASINS	411,000	1,084	379
● NON-ACTIVE BASIN			
TOTAL BASINS	305,000	35	8,714

CRUDE OUTPUT – DISTRIBUTION



AVERAGE PRODUCTION 1989 = 391 KBPD

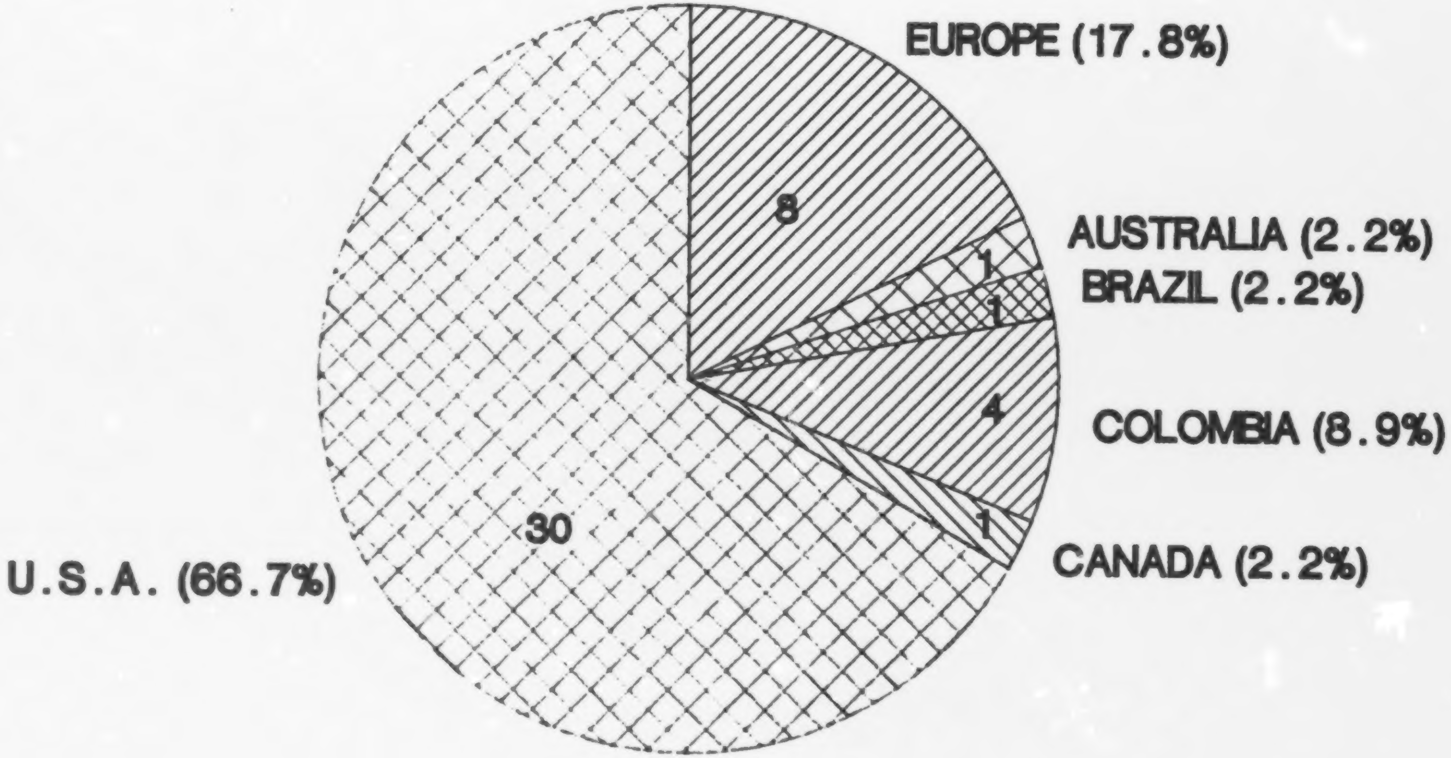
SEPTEMBER 1989 = 443 KBPD

EXPLORATION AND EXPLOITATION

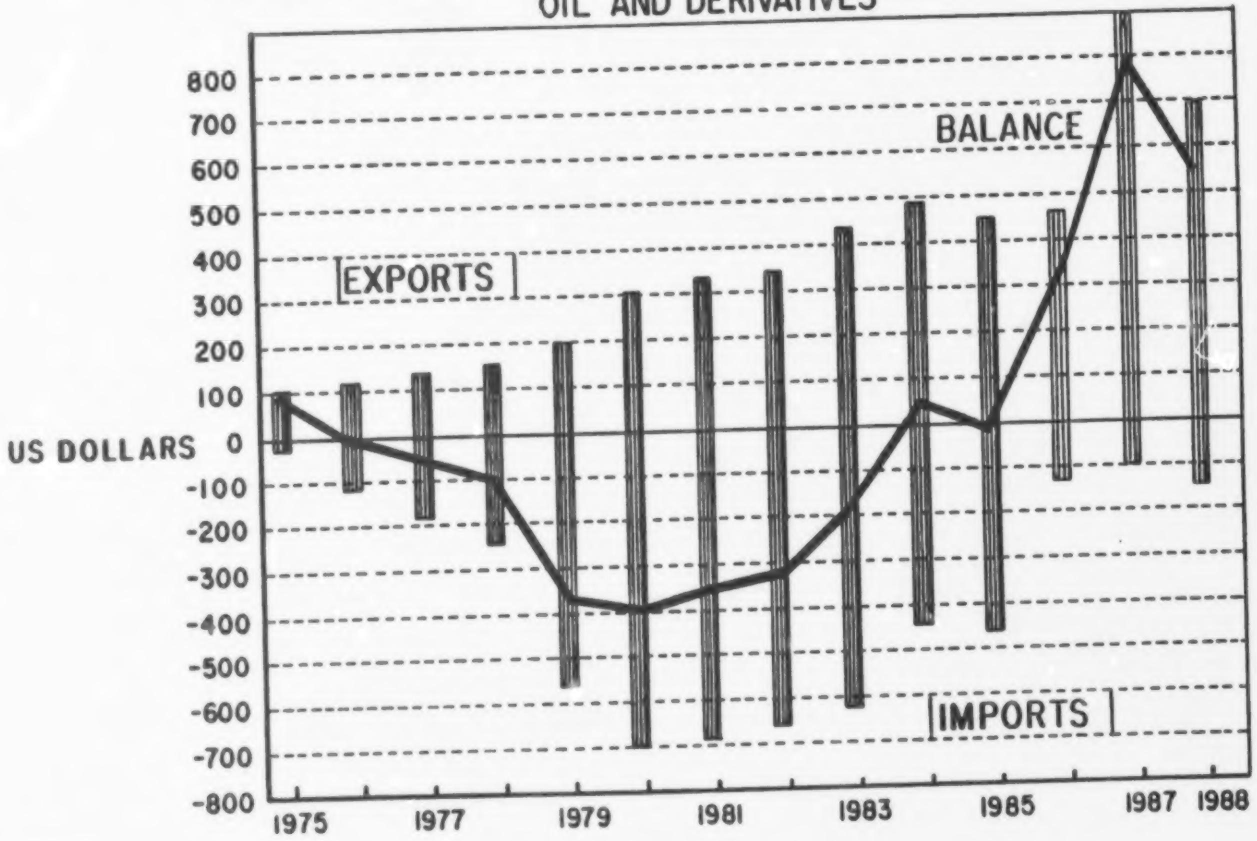
- FOREIGN COMPANIES WORKING IN COLOMBIA: 45
- ASSOCIATION CONTRACTS UNDERWAY: 96
- CONCESSIONS UNDERWAY: 14

FOREIGN COMPANIES WORKING IN COLOMBIA

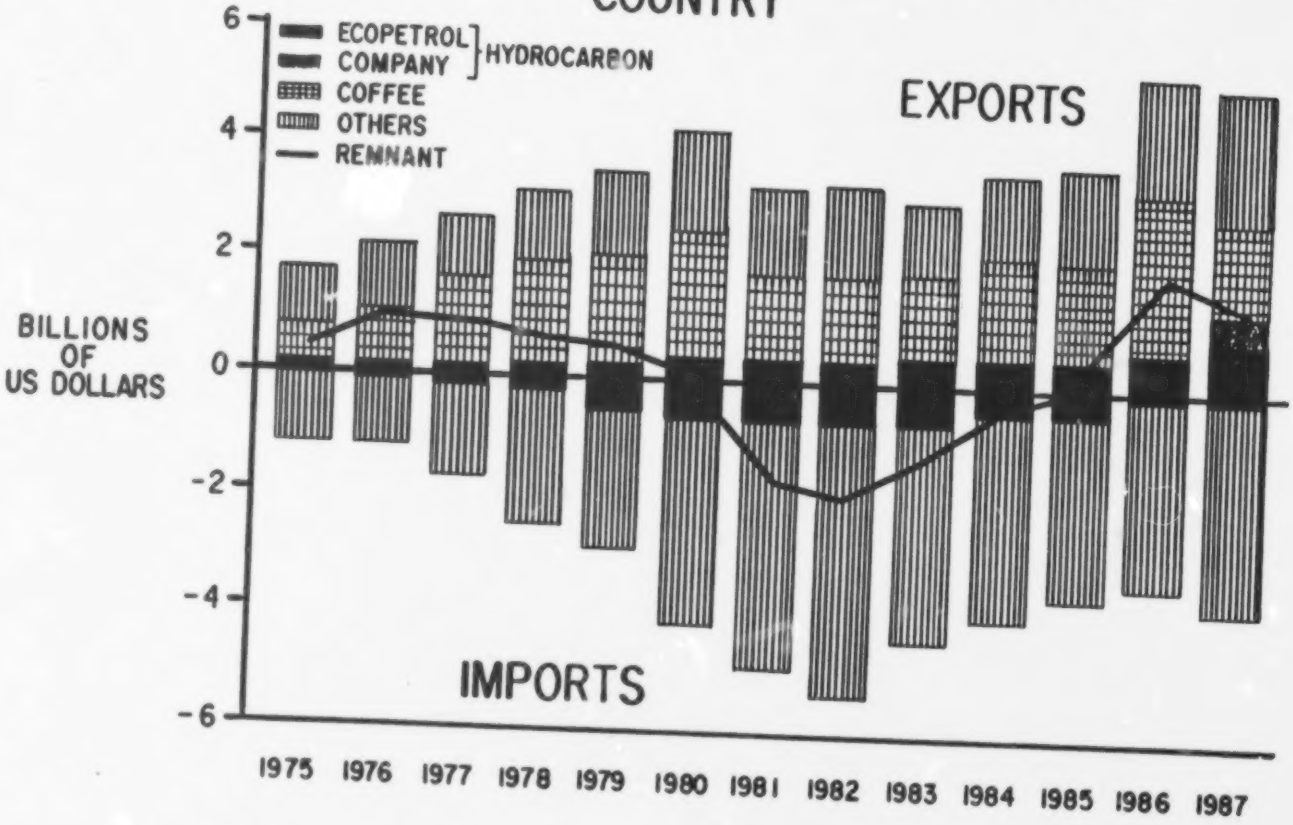
(%)



ECOPETROL'S BALANCE OF IMPORTS/EXPORTS
OIL AND DERIVATIVES



FRAMEWORK OF THE TRADE BALANCE OF THE COUNTRY



EXPLORATORY PLAN PROJECTION
1989 - 2000

	ECOPETROL	ASSOCIATION	INVESTMENTS Millions US $
● SEISMIC (Kms)	60,000	60,000	700
● WELLS	300	600	1.800
			2,500

EXPECTATION

Reserves to be discovered - PLAN	1,3	Billion barrels
Total reserves to be discovered	10,0	Billion barrels

EXPLORATION AND DEVELOPMENT COSTS
IN COLOMBIA
(US $ BL)

- **- COST FINDING**

1971 - 1982	1,16
1983 - 1989	0,55
1990 - 2000	1,50 - 2,00

- **- DEVELOPMENT COSTS**

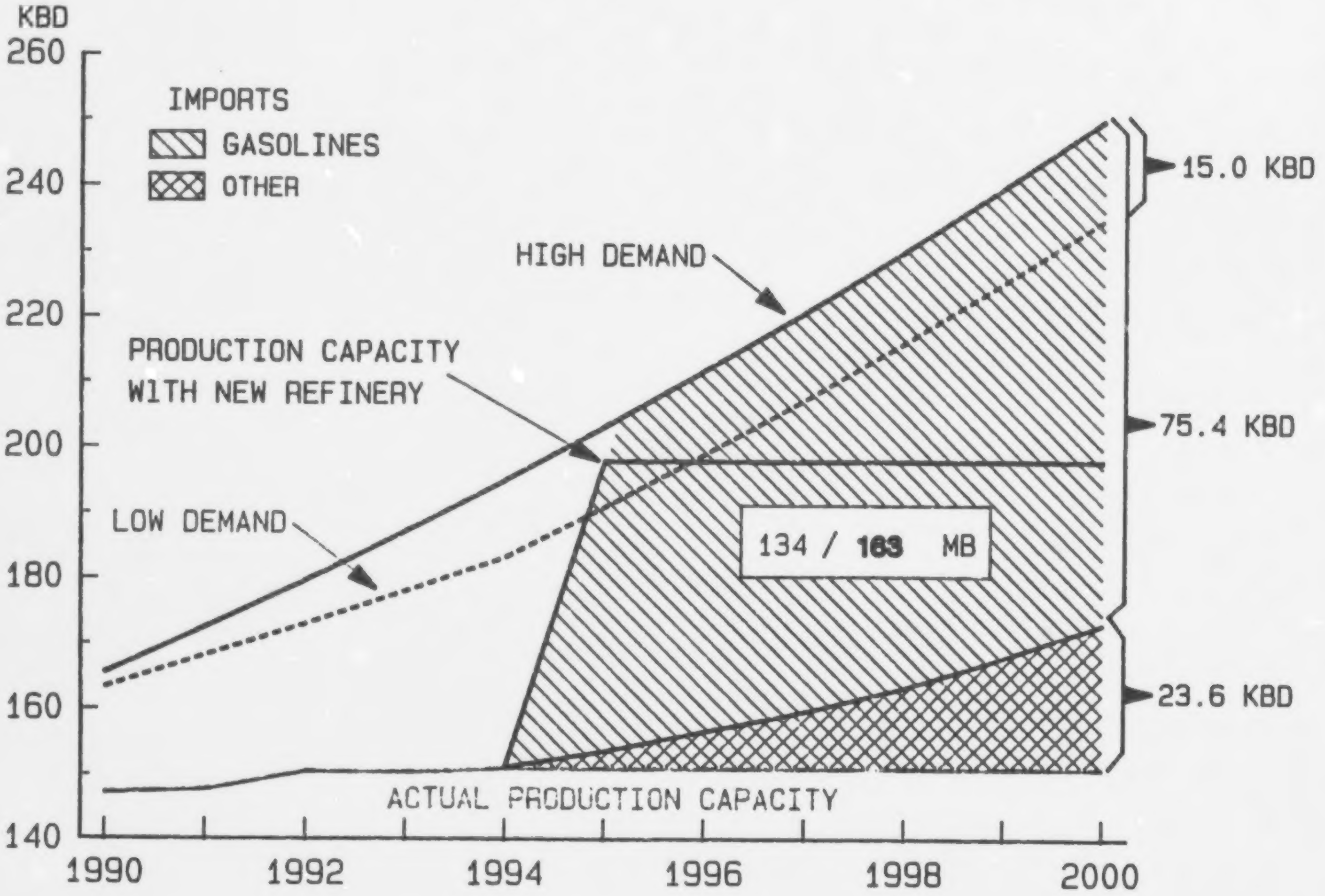
Development	0,50 - 1,50
Production	0,75 - 2,50
Transportation	0,50 - 3,00

LAND FOR DRILLING

(MHas)

ECOPETROL RESERVES:	8.6
ASSOCIATION CONTRACTS:	12.3
CONCESSIONS:	.4
AVAILABLE:	50.4

TOTAL WHITE PRODUCTS PRODUCTION AND CONSUMPTION



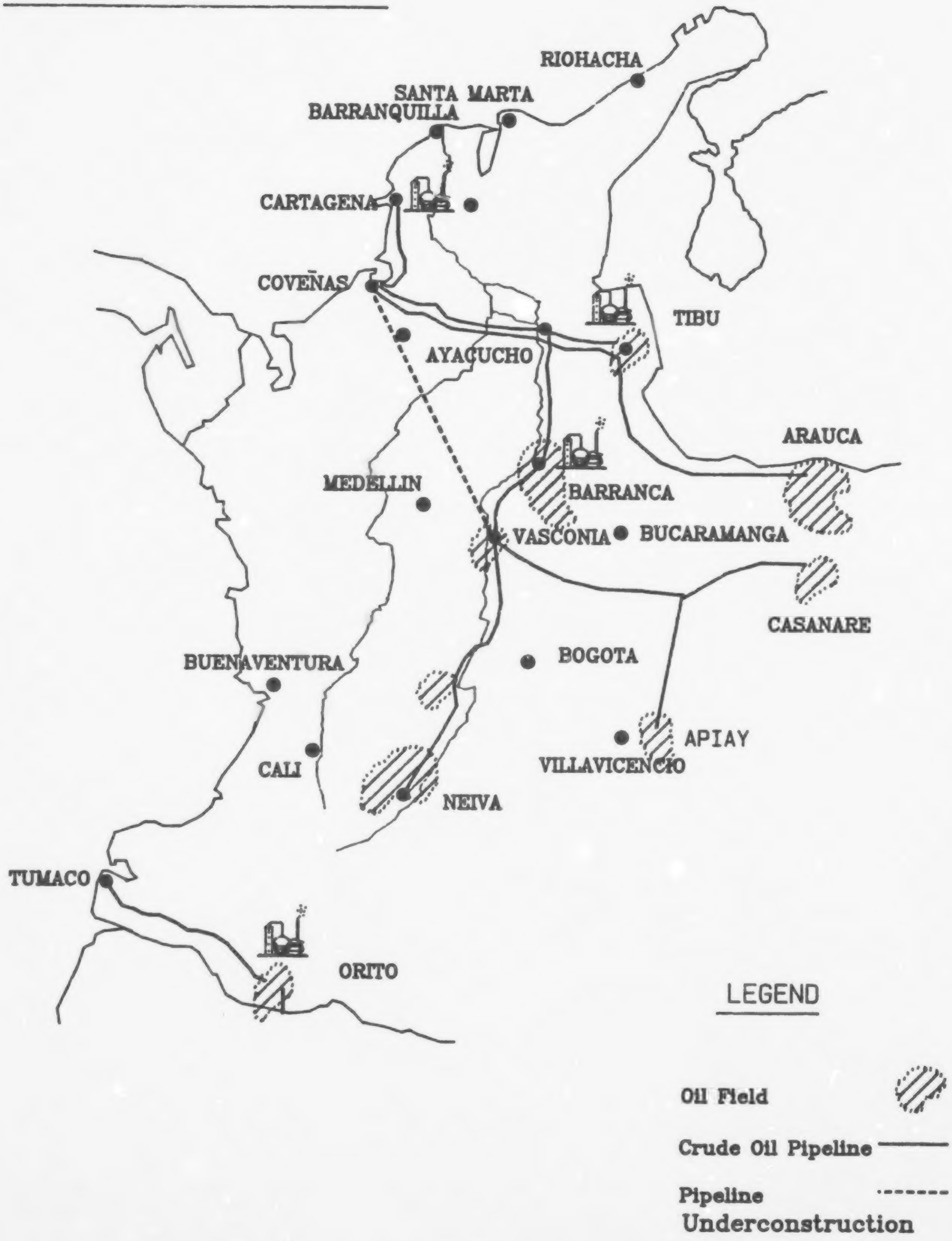
MEDIUM CONVERSION REFINERY

REFINING SCHEMES

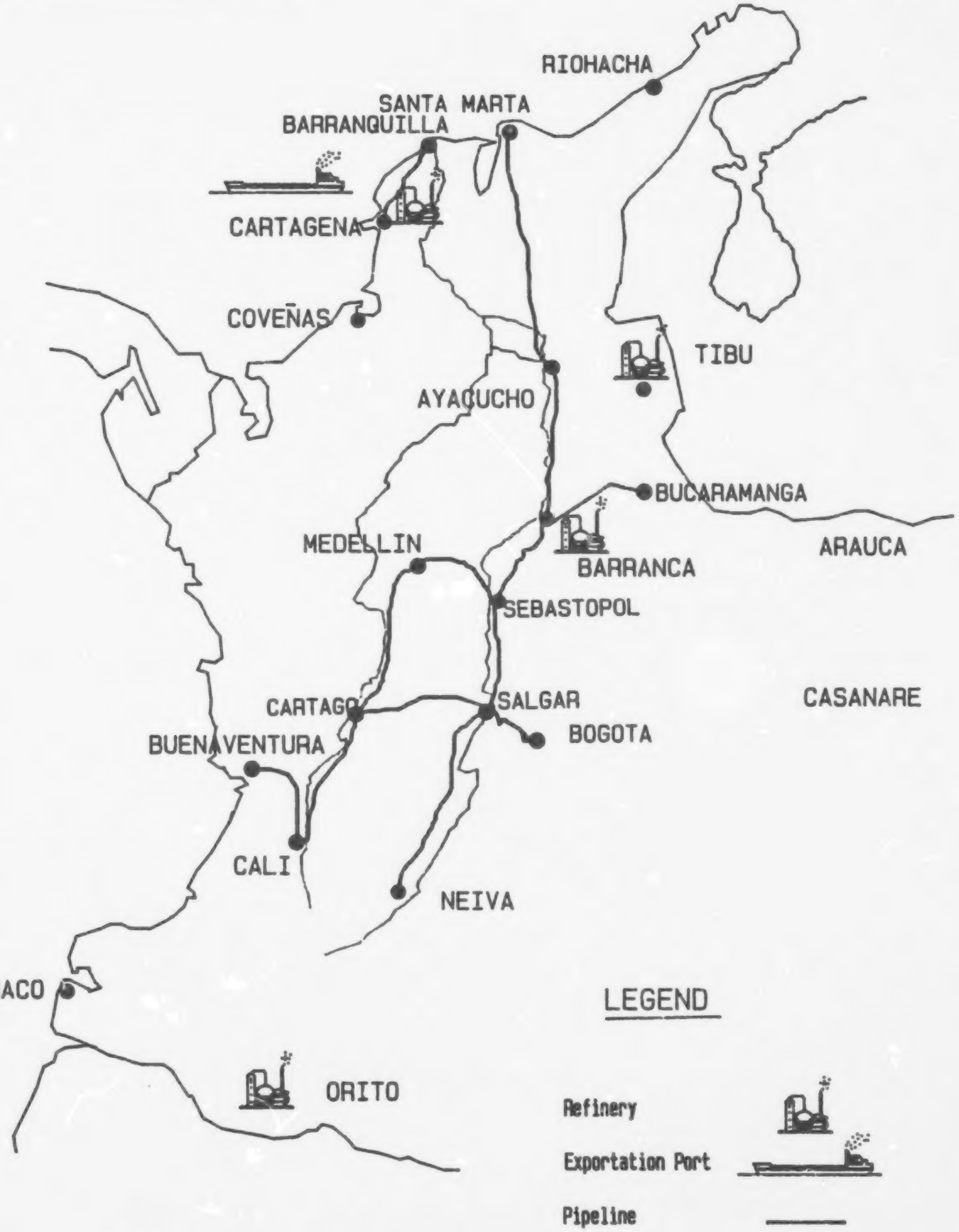
UNIT	CAPACITY (KB/D)
Atmospheric and Vaccuum Distillation	75
Visbreaker	27
Fluid Catalytic Cracking	37
Polymerization	4
Chemical Treatment	8
Storage	40

TOTAL INVESTMENT (MUS$) 760

CRUDE OIL PIPELINES


RIOHACHA
SANTA MARTA
BARRANQUILLA
CARTAGENA
COVEÑAS
TIBU
AYACUCHO
ARAUCA
MEDELLIN
BARRANCA
VASCONIA
BUCARAMANGA
CASANARE
BOGOTA
BUENAVENTURA
APIAY
CALI
VILLAVICENCIO
NEIVA
TUMACO
ORITO
LEGEND
Oil Field
Crude Oil Pipeline
Pipeline Underconstruction

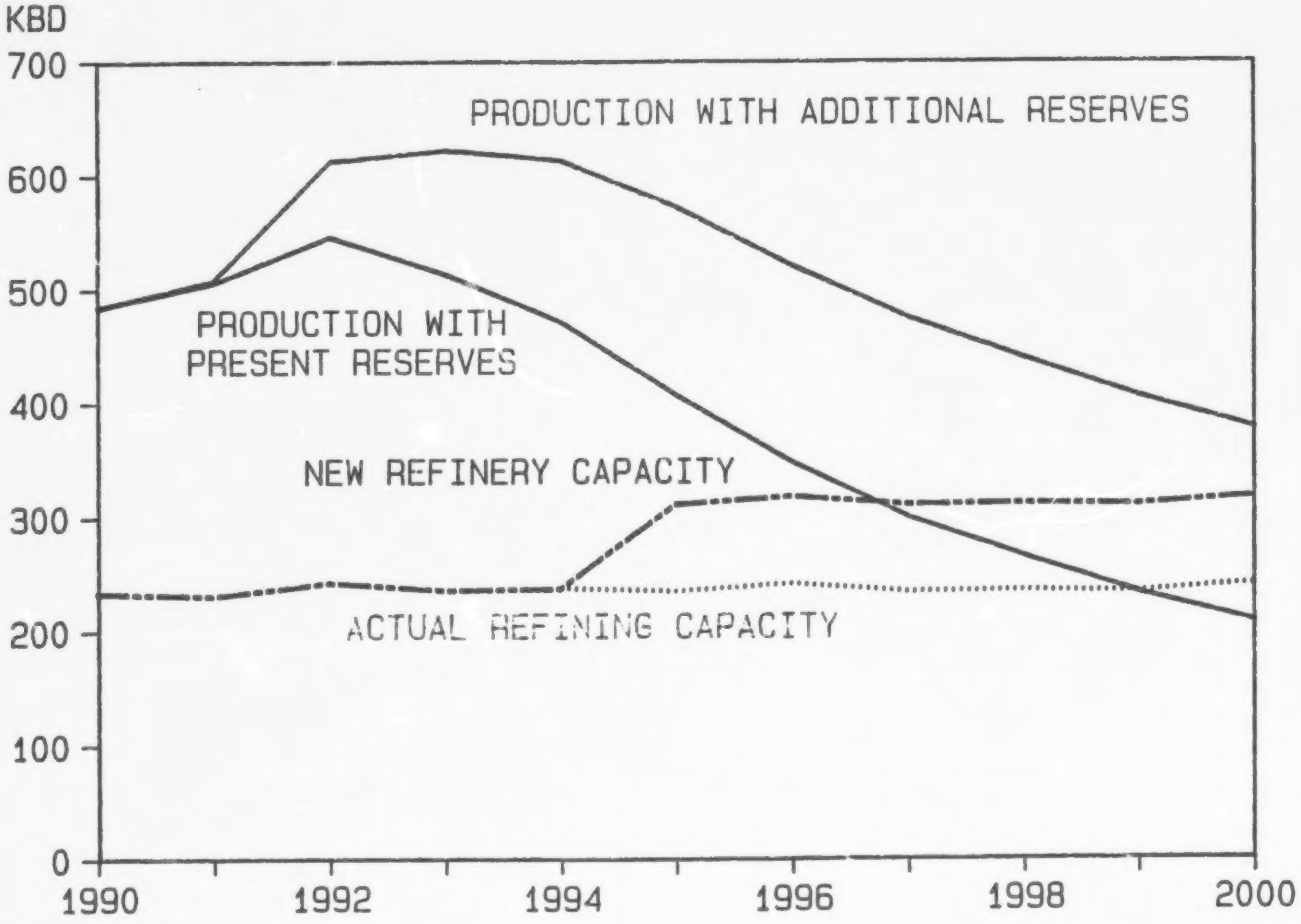
PRODUCTS PIPELINE


RIOHACHA
SANTA MARTA
BARRANQUILLA
CARTAGENA
COVEÑAS
TIBU
AYACUCHO
BUCARAMANGA
MEDELLIN
BARRANCA
ARAUCA
SEBASTOPOL
SALGAR
CASANARE
CARTAGO
BOGOTA
BUENAVENTURA
CALI
NEIVA
TUMACO
ORITO
LEGEND
Refinery
Exportation Port
Pipeline

NATURAL GAS

	PRODUCTION (MSCFD)	RESERVES (GCF)
NORTH COAST	270	3200
CENTRAL	130	900
TOTAL	400	4100

CRUDE OIL PRODUCTION AND CONSUMPTION FORECAST



PETROLEUM EXPLORATION AND DEVELOPMENT PROSPECTS IN AUSTRALIA

Presented by
Mr Bob Alderson,
Assistant Secretary,
Petroleum Policy Branch,
Australian Department of Primary Industries and Energy,

EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

INTRODUCTION

Although it is only twenty-five years since the first commercial petroleum discovery in Australia, the exploration industry has nonetheless risen to a place of importance in the Australian economy.

Australia is lightly explored by world standards - about 5500 wells, including development wells, in the entire Australian continent including the continental shelf area. By comparison, the United States petroleum exploration industry is over 100 years old and the first 5500 wells had been drilled by the end of 1867. Today, more than 5500 exploration wells are drilled in the United States every year and over 3 million wells have now been drilled in continental USA - an area comparable to that of Australia.

The industry in Australia is entering a new phase with marked changes in the pattern of both crude oil and natural gas production underway. Australia's crude oil production in the 1970's and 80's has been dominated by the Gippsland Basin fields. However, as the Gippsland Basin fields reach maturity and production declines, a new frontier is emerging in Australian exploration and development as the focus of the industry switches to underexplored areas elsewhere, particularly offshore where the potential for major new discoveries is greatest.

Onshore areas are also underexplored. While the potential of onshore areas is for smaller discoveries, this is offset by lower costs and the ready availability of infrastructure.

Significant oil discoveries in the Timor Sea and North West Shelf area, which have aroused the interest of explorers, and the commencement of LNG exports to Japan from the North West Shelf project centred on the North Rankin A platform, underline the importance and potential of this region. These events have signalled a new era in the development of the petroleum industry in Australia.

OVERVIEW OF CURRENTLY PRODUCING AREAS

Figure 1 shows the major sedimentary basins of onshore and offshore Australia.

Gippsland Basin

The Gippsland Basin in Bass Strait is Australia's major oil-producing basin and is also a significant gas producer. The bulk of production, currently around 300 000 bpd, is from 13 production platforms, Kingfish A, Kingfish B, Halibut, Fortescue, West Kingfish, Mackerel, Cobia, Tuna, Marlin, Snapper, Barracouta, Bream and Flounder. Production from the Gippsland Basin declined in 1988 and is expected to continue to fall.

Some of the decline will be compensated by production increases from the Bream platform, currently being brought on-stream, and future development of several small fields. The Bream platform is already producing more than 2100 kilolitres/day (13 000 barrels/day) from six of the eight development wells drilled.

The smaller fields being developed have the capacity to jointly produce oil at a peak rate of 4000 kilolitres/day (25 000 barrels/day). Small accumulations are economic to develop because of major production infrastructure in the area.

Further discoveries are likely in this basin. Its exploration potential and that of other basins considered most prospective are discussed elsewhere in this paper.

Cooper/Eromanga Basins

The Cooper Basin in Australia's interior, accounts for major gas production for the domestic market and together with the overlying Eromanga Basin, contributes significant crude oil and condensate to total Australian oil production. Over $2 billion dollars has been invested in surface infrastructure. This includes the Moomba, South Australia, gas and liquids plant, the facilities at Jackson, Queensland, and port developments in both eastern and southern Australia. Pipelines transport both oil and gas to eastern and southern industrial centres several hundred kilometres distant.

Identified remaining reserves in the Cooper and Eromanga Basins total 74 billion cubic metres of sales gas (2.6 trillion cubic feet) and 31 million kilolitres of oil and gas liquids (194 million barrels). Two States - South Australia and New South Wales - are dependent on gas supplies from the Cooper Basin with gas sales around 200 petajoules per year.

Additional markets are being established for natural gas from the Queensland part of the basin - this is expected to encourage additional exploration in the area. New pipeline construction in South Australia will reduce oil and gas production costs and be a stimulus to increased exploration there. Construction of a second oil refinery in South Australia is nearing completion.

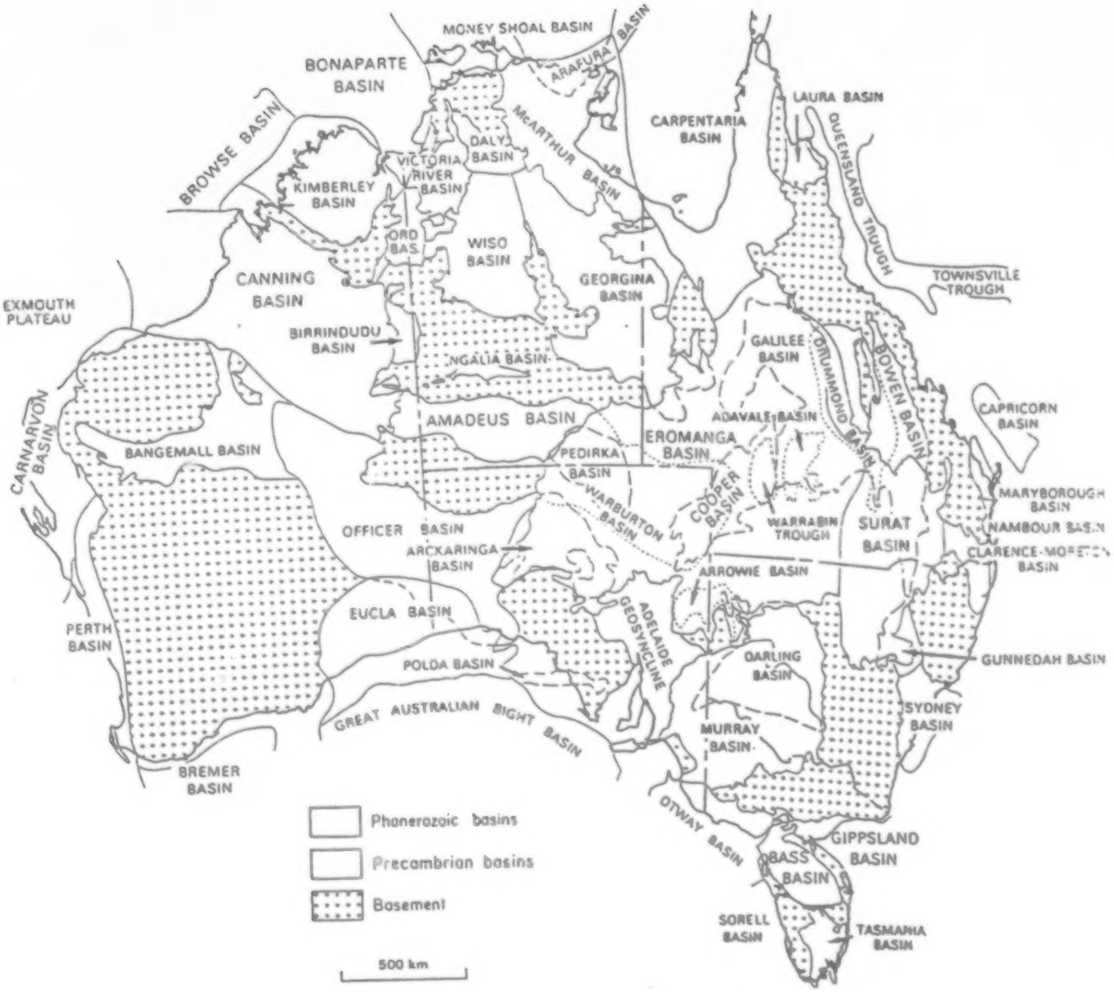

MONEY SHOAL BASIN
ARAFURA BASIN
BONAPARTE BASIN
BROWSE BASIN
KIMBERLEY BASIN
VICTORIA RIVER BASIN
DALY BASIN
McARTHUR BASIN
CARPENTARIA BASIN
LAURA BASIN
QUEENSLAND TROUGH
TOWNSVILLE TROUGH
ORD BAS.
WISO BASIN
GEORGINA BASIN
CANNING BASIN
EXMOUTH PLATEAU
BIRRINDUDU BASIN
NGALIA BASIN
GALILEE BASIN
DRUMMOND BASIN
BOWEN BASIN
CAPRICORN BASIN
CARNARVON BASIN
BANGEMALL BASIN
AMADEUS BASIN
ADAVALE BASIN
EROMANGA BASIN
PEDIRKA BASIN
WARBURTON BASIN
COOPER BASIN
WARRABIN TROUGH
SURAT BASIN
MARYBOROUGH BASIN
NAMBOUR BASIN
CLARENCE-MORETON BASIN
OFFICER BASIN
ARCKARINGA BASIN
ARROWIE BASIN
EUCLA BASIN
PERTH BASIN
ADELAIDE GEOSYNCLINE
DARLING BASIN
GUNNEDAH BASIN
POLDA BASIN
SYDNEY BASIN
GREAT AUSTRALIAN BIGHT BASIN
MURRAY BASIN
BREMER BASIN
OTWAY BASIN
GIPPSLAND BASIN
BASS BASIN
SORELL BASIN
TASMANIA BASIN
Phanerozoic basins
Precambrian basins
Basement
500 km

FIGURE 1

Amadeus Basin (Central Australia)

This basin contains the 'oldest' commercial hydrocarbons in Australia, with both oil and gas being produced from early Palaeozoic reservoirs. Production from two fields, the Palm Valley gas/condensate field and the Mereenie oil field commenced in 1984. Evaluation of the oil reserves in the Mereenie field is still continuing. Gas from this field supplements Palm Valley production.

The basin's estimated remaining petroleum reserves at 31 December 1988, comprise 5.32 million kilolitres (33.5 million barrels) of oil, 1.34 million kilolitres (8.73 million barrels) of natural gas liquids and 298 billion cubic feet of sales gas.

Developments aimed at utilizing Amadeus Basin gas include natural gas reticulation in Alice Springs, and manufacture of liquefied natural gas (LNG) at a small scale liquefaction plant in Alice Springs for power supply at nearby tourist facilities and mining operations.

Palm Valley gas/condensate and Mereenie oil is transported to Alice Springs by 20 cm diameter pipelines. A 1600 km, 35 cm pipeline from the Palm Valley field supplies gas to Darwin power stations. In addition, a gas separation plant at Darwin will produce LNG and provide Australia's only source of helium.

Timor Sea

At the Jabiru oil field, continued development drilling has resulted in an increase in the production rate of oil from 2500 kilolitres/day (16 000 barrels/day) to 7200 kilolitres/day (45 000 barrels/day) since production commenced in August 1986. Recently, initial reserves were upgraded to approximately 80 million barrels. Twenty one million barrels have already been produced.

The nearby Challis and Cassini oil fields are being developed at an estimated cost of $A250 million for production start-up in late 1989. A floating production facility will be used to produce oil at a rate of about 24 000 bpd.

Another discovery being considered for development is the Skua field. Oil reserves could be in the order of 30 million barrels.

North West Shelf

North West Shelf liquid natural gas development is the largest resources development project yet undertaken in Australia. The second of three LNG trains is expected to start up late in 1989. By 1993 all three trains should be on stream allowing exports of LNG to Japan to rise to 6 million tonnes/year in 1995. Testing and appraisal drilling on the North Rankin and Goodwyn fields have confirmed remaining natural gas reserves of 10 trillion cubic feet and condensate reserves of about 400 million barrels.

Carnarvon Basin

The northern Carnarvon Basin contains a number of small and medium sized oil and gas fields. Barrow Island is the largest oil field outside the Gippsland Basin. It has initial reserves of around 300 million barrels and is now around 80% depleted.

Numerous small oil fields in the region have or are being developed. These fields have combined remaining reserves of 11 million kilolitres (68 million barrels). Proximity to production facilities and innovative production techniques make these small fields viable in this area.

EXPLORATION PROSPECTS

BMR Estimates

The Australian Bureau of Mineral Resources, Geology and Geophysics is the major advisor to government on Australia's petroleum resources and prospectivity. BMR began developing its own methodology for quantitative assessments about ten years ago and a number of its assessments of crude oil, natural gas and condensate resources have been published since 1979. BMR's methodology for assessment of undiscovered petroleum resources has a geological rather than a statistical basis and uses estimates of the area of closure and volume of recoverable oil and gas per unit area of each undrilled trap. A computer program simulates drilling of each trap type in each play in each sub-basin.

The assessments made using the BMR method indicate potential within Australia as shown in Table 1.

Table 1.

Australian Petroleum Potential

	(millions of kilolitres)			(millions of barrels)		
	low	high	avge	low	high	avge
Crude Oil	160	800	380	1000	5000	2400
	low	high	avge	low	high	avge
Condensate	40	140	80	250	880	500
	(billion cubic metres)			(trillion cubic feet)		
	low	high	avge	low	high	avge
Sales Gas	300	1300	650	10	45	23

Source: Australian Bureau of Mineral Resources.

The 1986 BMR assessment of undiscovered oil resources compares closely with the 1987 assessment of Esso Australia Ltd, the only other published estimate. Esso's 1987 assessments of undiscovered gas and condensate are generally more optimistic than those of BMR (1986), with moderately large amounts of gas liquids considered likely to be discovered as part of the gas discoveries.

The average estimates of undiscovered crude oil and sales gas in what BMR considers to be Australia's eight most prospective sedimentary basins are shown in Figure 2. Six of these eight basins are primarily in offshore areas, and four are in the west and northwest of Australia. The basins of northeast Queensland can be regarded as a frontier area for exploration, with minimal drilling and only regional seismic data. At the other end of the scale, the potential is still good for discovery of additional oil resources in the Gippsland Basin, the best explored basin in Australia.

The computer model permits examination of assessments by geological age. The Jurassic to Recent sequence is believed to have the greatest potential for further oil discoveries and the Permian and Triassic sequence the greatest potential for further gas discoveries. Both of these sequences are being targetted by explorers in Australia's northwest. Similarly, looking at the potential of different trap types, the assessments indicate that fault traps, faulted anticlinal traps and stratigraphic traps will be of increasing importance in future exploration in Australia.

These assessments are conservative and refer only to conventional oil and gas accumulations contained in structures, or stratigraphic traps that are not presently known to contain petroleum and that could be brought into production in the next 20 to 25 years. Hence the assessments exclude new pool discoveries to be made in Australia's identified fields and also excludes accumulations that may occur in water depths greater than 200 m and in remote areas, such as along parts of Australia's southern margin and in the offshore territories.

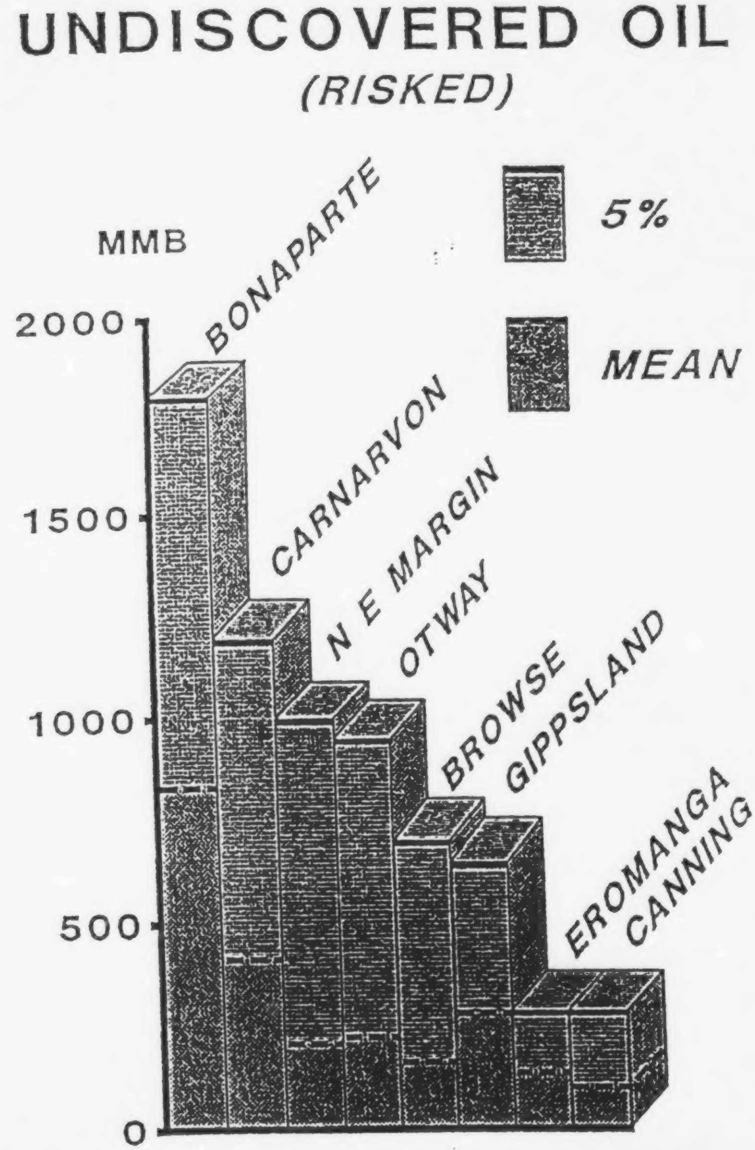
Exploration Review

Bonaparte (Timor Sea)

This area was the most actively explored in 1988, and activity is continuing strongly in 1989. Exploration work programs are targetting some objectives based on new play concepts for the area, including testing of combined structural-stratigraphic traps. The main oil plays are Jurassic and Triassic fluvio-deltaic clastic reservoirs, with secondary objectives in rift sediments of Permian age (for gas) and Cretaceous marine turbidites.

Significant discoveries, three oil and one gas, were made in three of the fourteen new field wildcat wells drilled in the area in 1988. Appraisal drilling is continuing at the Cassini, Skua and Puffin oil fields, and at the Petrel gas field and a wildcat well has been drilled in the Puffin field.

Bureau of Mineral Resources estimates additional undiscovered resources for the region up to about 290 million kilolitres (1800 million barrels) of crude oil and up to about 140 billion cubic metres (5 trillion cubic feet) of sales gas. Significant additional potential for both oil and gas occur in the Browse Basin to the immediate south.



BMR 89/173D

FIGURE 2

The Chief Executive of BHP Petroleum recently suggested that the Timor Sea area has a 1 billion barrel oil potential.

Carnarvon

All the economic and potentially economic accumulations have been located within a thick Mesozoic sequence in the northern part of the basin which contains the prospective Barrow and Dampier Sub-basins and the Rankin Platform, the site of the Northwest Shelf LNG project.

Exploration for oil is currently focused on the faulted southern margin of the Barrow Sub-basin, near existing small fields. Potential also exists for discovery of medium-sized fields on the northern margins of both sub-basins. The recent Wanaea oil discovery is apparently the largest accumulation discovered since the Barrow Island field.

Bureau of Mineral Resources estimates additional undiscovered resources for the region of up to about 210 million kilolitres (1300 million barrels) of crude oil and up to about 740 billion cubic metres (26 trillion cubic feet) of sales gas. Significant condensate potential is expected with the sales gas in this area.

Gippsland (Bass Strait)

Most of the oil resources discovered so far in Australia are in the offshore part of the Gippsland Basin, southeastern Australia. Major fields are located in large anticlines at the top of the early Tertiary Latrobe Group, in the Central Deep area of the basin. Several smaller fields are developed in intraLatrobe Group sediments and others are located along the margins of the basin, away from the Central Deep area.

Almost all the intra-Latrobe Group accumulations occur in high-risk fault-dependent closures, so that there are few deep wells in areas where seismic data are of poor quality. Recent re-mapping of several intra-Latrobe horizons by BMR using industry data has modified the structural interpretation of the southern basin margin and has identified other areas in which seismic surveys using new technology could improve interpretation of the deeper structures.

There is renewed exploration interest in this proven oil-prone area following the discovery in 1986 of the intraLatrobe Group Kipper gas/oil accumulation near the northern margin of the basin.

Bureau of Mineral Resources estimates additional undiscovered resources for the region of up to about 80 million kilolitres (500 million barrels) of crude oil and up to about 30 billion cubic metres (1 trillion cubic feet) of sales gas.

Otway

The Otway Basin lies both on and offshore in southern Australia and is one of three basins within the Bass Strait area. By

Australian standards, the basin is considered moderately well explored, with about 89 new-field wildcats drilled since 1959, 17 offshore and 72 onshore in a total basin area of 72 000 square kilometres (to 200 metres bathymetric contour).

Several exploration objectives are present within the Mesozoic and Tertiary basin fill. A majority of wells drilled had primary objectives in the Late Cretaceous and Tertiary sequence. A number of wells also targetted the nonmarine Early Cretaceous sequence.

Three small gas fields have been discovered onshore in the basal Late Cretaceous sequence in Victoria. At present these supply gas to a small local market. Exploration confidence in the Early Cretaceous has been boosted by the recent Katnook gas/condensate discovery in onshore South Australia.

The Otway Basin, particularly offshore, has been assessed by BMR as having significant potential for oil discoveries. Strandings of bitumen along the coastline in the western part of the basin are thought to have originated from submarine seeps and to be derived from lacustrine source rocks. Thermogenic gas anomalies in sea-floor sediments were detected at eleven localities in the western part of the basin during a research cruise in the area in early 1987 by the BMR's research vessel 'Rig Seismic'. New seismic data collected by BMR during 1985-88 has demonstrated structural closures throughout the basin on several horizons as deep as intra-Early Cretaceous.

Bureau of Mineral Resources estimates additional undiscovered resources for the region up to about 130 million kilolitres (850 million barrels) of crude oil. The region has a low gas potential.

Canning

The Canning Basin contains about 17 000 m of Palaeozoic, Mesozoic and Cainozoic sedimentary rocks and covers an area of 43 000 square kilometres onshore and 165 000 square kilometres offshore (to 200 m bathymetric contour). To May 1986, a total of only 118 new-field wildcat wells had been drilled in this very large area. Palaeozoic rocks predominate onshore and Mesozoic sediments offshore. The basin has a complex structural and sedimentary history including several episodes of rifting.

Onshore exploration is concentrated in the northern part of the basin, where four small fields have been discovered in Devonian and Permian reservoirs. Few wells have been drilled in other parts of the basin, both on- and offshore. The most successful plays to date have been Devonian reefs and structural traps containing reservoirs of Carboniferous sandstone. A major BMR study of the petroleum potential of the basin, with emphasis on basin structure and depositional history commenced in 1988; the geological phase, which will incorporate new models of reef development based on BMR research, will begin in 1990, following completion and interpretation of seismic data acquired in 1988-89.

The deeper section of the Mesozoic sequence offshore is considered to have potential for gas discoveries.

Bureau of Mineral Resources estimates additional undiscovered resources for the region up to about 45 million kilolitres (300 million barrels) of crude oil and up to about 60 billion cubic metres (2 trillion cubic feet) of sales gas.

Cooper/Eromanga

A total of 110 appraisal and new-field wildcat wells were drilled in the Cooper/Eromanga Basins in 1988. Since the first discovery of commercial gas at Gidgealpa in 1963, 100 gas and 10 oil fields have been discovered in the Permo-Triassic Cooper Basin.

While all the known large and medium-sized anticlinal closures in the Cooper Basin have been drilled, there is a large number of smaller structural traps as yet undrilled, with additional potential in the deeper section, and in stratigraphic traps. Improved seismic data quality resulting from new acquisition and processing techniques now in use and better depositional modelling are expected to result in further discoveries.

Within the Jurassic to Early Cretaceous Eromanga Basin, which overlies the Cooper Basin and several other sub-basins, 21 million kilolitres of oil (133 million barrels) and 1.3 billion cubic metres of sales gas (48 billion cubic feet) have been found in 85 oil and 7 gas fields. New markets, additional pipeline development and the continuing high success rate for new-field wildcat wells in the area are expected to continue to stimulate activity.

A new play concept invoking a Cooper source/Eromanga reservoir has resulted in several new discoveries. Other new plays with potential for large hydrocarbon reserves are a number of postulated impact structures of Cretaceous age; such structures have potential to entrap large volumes of hydrocarbons.

The Eromanga Basin covers 1 million square kilometres onshore in Australia and, with the underlying Cooper Basin, is currently, still the most actively and successfully explored basin onshore in Australia. Some 20 new accumulations were found by the 50 Eromanga new-field wildcat wells drilled in 1988 alone and 13 new pools were found by appraisal drilling in existing fields. Much of this activity was focused on the area overlying and immediately adjacent to the Cooper Basin. There is potential for additional discoveries in the Eromanga sequence elsewhere in this large, sparsely explored basin: drilling density is low and stratigraphic potential unknown.

Identified remaining reserves in the combined Cooper/Eromanga Basins total 74 million cubic metres of sales gas (2.6 trillion cubic feet) and 31 million kilolitres of oil and gas liquids (194 million barrels).

Bureau of Mineral Resources estimates of additional undiscovered resources for the region, mainly the Cooper and Eromanga Basins, but including some small but economic oil and gas fields in other basins, are between 10 and 80 million kilolitres (60 to 500 million barrels) of crude oil, between 25 and 90 billion cubic metres (0.9 to 3.3 trillion cubic feet) of sales gas and between 4 and 15 million kilolitres (25 to 100 million barrels) of condensate.

Review of other prospects

Bass

The Bass Basin in Bass Strait contains a similar sedimentary sequence to that of the adjacent producing Gippsland Basin. The major exploration target is the Late Cretaceous to Early Tertiary sequence, which has been intersected in 25 new-field wildcat wells. This sequence provides good source, reservoir and seal. The Bass Basin, however, lacks traps in structural/topographic highs associated with a widespread unconformity at the top of the Early Tertiary, the major exploration play of the Gippsland Basin. Structural and stratigraphic traps are present within the target sequence.

The Early Cretaceous is an exploration objective in the adjacent Otway Basin. Only one well has intersected Early Cretaceous sediments in the Bass Basin beneath the major target.

One gas, and two oil/gas fields have been discovered in the target sequence and another possible discovery awaits further evaluation. Significant hydrocarbon shows were encountered in several other wells. The main potential for further discoveries is thought to occur in anticlines and fault traps within the target sequence.

Perth

The Perth Basin, both on and offshore, is moderately explored and has had modest success. Offshore, 19 new-field wildcat wells were drilled between 1969 and 1985, with three commercial oil discoveries. Onshore, 58 new-field wildcats since 1961 resulted in discovery of one oil, two oil/gas and six gas accumulations. Gas from the northern onshore part of the basin is produced for the local market.

The basin contains over 12 000 m of Silurian and Permian to Tertiary sedimentary rocks. Exploration offshore has targetted Cretaceous sediments in structural traps or palaeotopographic highs in the central part of the basin. Onshore, there are several objectives in Permian, Triassic and Jurassic sequences.

The Perth Basin is considered to have fair to moderate potential for further discoveries. Fourteen areas in the offshore part of the basin have recently been released for bidding under the modified work program bidding system, with a closing date in February 1990.

Amadeus

Two economic (1 oil and gas/condensate, and 1 gas/condensate) and fourteen uneconomic (6 oil, 7 gas and 1 oil/gas) petroleum accumulations have been discovered since 1963 in the Amadeus Basin of central Australia. About 30 petroleum exploration wells have been drilled, mainly in the northern part of the basin.

The petroleum in the Amadeus Basin mainly occupies structural, fold-related traps within Upper Proterozoic to Lower Palaeozoic sedimentary and evaporitic rocks, which provide source, reservoir and seal. The petroleum is believed to be of algal/bacterial origin.

The Lower Palaeozoic sequence appears to contain the best prospects for future discoveries, in anticline and fault traps in the north and northwest where the sequence is thickest.

EXPLORATION OPPORTUNITIES OFFSHORE AUSTRALIA

The foregoing has outlined the potential of the major sedimentary basins in Australia and has demonstrated that these basins are generally underexplored. Where then, will opportunities arise over the next 10 to 15 years for companies wishing to explore in Australia, particularly offshore where the potential is greatest?

Current Hot Spots

There are three regions which are attracting interest, which have proven production, and for which there are still new opportunities. These regions cover the Gippsland Basin, the Timor Sea (Bonaparte/Browse Basins) and the North West Shelf (Carnarvon Basin).

Exploration acreage is continually being made available in these proven areas.

Re-appraisal and New Opportunities

Over the next 5 years a special effort is being made to open up exploration in basins where new ideas and techniques can be brought to bear. A significant discovery in these basins - and there is substantial potential - can be the catalyst for a new prospectivity appraisal. You need only to look at the Jabiru discovery in 1984 to see how the industry has totally reassessed the Timor Sea region.

The offshore regions of interest in this category of exploration opportunity include the Otway Basin, the Great Australian Bight, the Perth Basin and the Bass Basin, and perhaps a new look at the Exmouth Plateau and the Gulf of Carpentaria.

Planning for the release of areas in 1990 is underway. Areas being considered are those in the Otway Basin, the North West Shelf, the Timor Sea and possibly the Great Australian Bight.

Longer Term Opportunities

The Australian Continental Shelf is very large. For this reason there are offshore regions which as yet have had no more than broad scientific investigation. The petroleum potential is unknown and unlimited. Areas such as the Queensland and Townsville Troughs, the East Capricorn Basin, the Lord Howe Rise and the Kerguelen Plateau will offer significant opportunities to explorers in the longer term.

The message that this survey of the petroleum potential of Australia conveys, is that this country can offer a complete portfolio of exploration acreage ranging from low risk to high risk, and from the short term to the long term. The Government is keen to see a stronger role for existing explorers and to attract new players in order to fully realise our petroleum potential.

The geological opportunities are there - what about Government policies to attract the necessary investment.

EXPLORATION PROGRAM

Administration Arrangements for Petroleum Exploration and Development

Australia does not have a national oil company. Petroleum exploration and development is undertaken by the private sector.

In Australia, all petroleum exploration and development activity is carried out under a title system of permits and licences, with companies being responsible for decision making within a broad framework of rules laid down by the Government. Any oil or gas produced becomes the property of the oil companies once it is out of the ground.

Responsibility for Australia's offshore areas beyond the 3 nautical mile Territorial Sea rests with the Federal Government, whereas onshore and within the Territorial Sea, petroleum operations are the responsibility of the individual State and Territory Governments.

Petroleum (Submerged Lands) Act and other Regulatory Systems

One of the most important areas of Government policy directly affecting the exploration industry is access to exploration areas including the legal arrangements for acquisition of titles and the security of those titles. As the Commonwealth Government in Australia only has direct jurisdiction in the offshore area, the following comments are confined to that area. It should be noted, however, that the onshore arrangements are not significantly different.

The Government's aim is to provide access to acreage within a legal regime which clearly sets out the rights and obligations of titleholders and Government. In this respect, it is also important that these arrangements reflect the long term nature of investment decisions in the industry.

The Petroleum (Submerged Lands) Act 1967 is the governing legislation for Australian offshore petroleum activity. Over recent years, a number of changes have been made to improve the efficiency and equity of title acquisition and tenure arrangements.

The method of acquisition of petroleum exploration permits in Australia is generally on a work program basis. That system, which has been refined in recent years, requires that an application for an exploration permit must be accompanied by particulars of the proposed work and expenditure program for the initial six year term of the permit. Assessment of the application takes into account factors, such as the number of wells to be drilled, the extent to which proposals reflect available technical information on prospects in the area, and the technical and financial capacity of the applicants to fulfil the proposed work commitments. The applicants must put forward a guaranteed work program for the first three years, with the second three year program being open to negotiation depending on the success of the earlier work.

Alternatively, in highly prospective offshore areas, cash bidding may be used as the method of permit award. The Government's objective in introducing the cash bidding system was to provide an efficient and equitable system of awarding permits where competition is expected to be intense - an objective which on past experience was not being met by the work program bidding system.

There is no obligation to undertake a specific exploration program in a permit awarded by cash bid, so companies are able to adjust their exploration plans to the prevailing economic conditions.

Regular Releases of Offshore Acreage

In its efforts to encourage exploration, the Government has adopted a strategy, in co-operation with the States and the Northern Territory, of releasing acreage at approximately six monthly intervals. In 1989, twenty-four areas have been released for the award of offshore petroleum exploration permits.

The first release in 1989 was announced in April, with areas being released in the Bass Basin and the Bonaparte Basin in the Timor Sea. Applications closed on 4 August and are currently being examined.

The second release in 1989 was announced on 14 August, with ten areas being released in the Perth Basin (Western Australia), one area in the Carpentaria Basin (Queensland) and one area in the Bass Basin (Tasmania). Applications for these areas close in February 1990.

Planning for the release of areas in 1990 is underway. Areas being considered are those in the Otway Basin, the North West Shelf, the Timor Sea and possibly the Great Australian Bight.

The areas included in these releases are determined in consultation with petroleum companies involved in exploration, State Governments and the Federal technical advisory body, the BMR. Companies are actively encouraged to identify areas which they wish to see included in future bidding rounds.

Rig Seismic

A major Continental Margins Program of offshore basin studies is carried out using a state of the art geoscientific research vessel, 'Rig Seismic', contracted by the Bureau of Mineral Resources for a period of ten years.

The vessel is equipped for both high-resolution seismic acquisition and for lower resolution, deep penetration seismic to provide maximum flexibility in basin studies. Geological samples can be obtained from the sea floor in water depths exceeding 4000 metres. On-board computer systems and laboratories are constantly updated and the range of scientific equipment expanded to embrace new and better ways of assessing prospectivity.

The vessel recently acquired capability for continuous underway analysis of light hydrocarbons and carbon dioxide in sea water. Mapping of light hydrocarbon distributions in potential prospective areas both on a local and regional scale may provide direct evidence of gas seeps, the nature of the seeps and the possible type of accumulation which supports the seep, and is a relatively inexpensive method of defining the presence and distribution of mature source rocks.

The indicative program for the Rig Seismic through 1989 and 1990 is as follows:

- SE Queensland - Regional (seismic and geology)
- Sydney Basin - Regional (seismic)
- Vulcan Graben/Browse Basin - Detailed (geochemistry)
- Vulcan Graben/Browse Basin - Deep structure (seismic)
- North West Shelf - Deep structure (seismic)
- North West Shelf - Detailed (geochemistry)
- Torres Shelf - Detailed (seismic and geology)
- South Carnarvon Basin - Regional (seismic)
- Bonaparte Gulf/Timor Sea - Regional/Deep Structure (seismic)
- Southern Margin - Regional (geology).

These projects will follow on those already in the 1988/89 forward program. However, they will be scheduled to maintain the present mix of three or four seismic cruises, one or two geological cruises and one geochemistry/geological cruise per year, as well as to take account of the timing of new acreage releases and changes in areas and emphasis of exploration interest and activity. Expected short term benefits are:

- identification of new structures and development of new play concepts on the North West Shelf, offshore South East Queensland and central New South Wales
- the development of new geochemical techniques for both frontier and prospect exploration in the Browse Basin and Vulcan Graben.

POLICY

The Federal Government has specific economic, social, legal and taxation powers that shape the framework within which petroleum companies operate in Australia.

At both the macro and micro-economic level, the Federal Government has been developing policies aimed at creating an environment where efficient industries can grow and develop in an internationally competitive environment. The Government's approach has been directed towards reducing unnecessary regulation and other impediments to change, and encouraging resources to flow to areas where they will maximise overall output and income. They are aimed at making the Australian economy more open and dynamic.

Some of the changes particularly relevant to the petroleum industry include

- a reduction in the company tax rate from 49% to 39% while retaining immediate deductibility of exploration expenditure against income from any source for company tax purposes
- removal of a 2% revenue duty on imports - a saving to capital intensive projects such as petroleum developments
- progressive cuts in tariffs on manufactured goods - in line with the Government's commitment to promote industry competitiveness and efficiency, the general level of tariffs on imports is to be reduced to 10 per cent and 15 per cent, depending on the tariff category of the item, over the next three to four years - this move will lead to lower costs for the petroleum sector which utilises a significant amount of imported capital equipment
- reform of the labour market, with a view to enhancing skill levels and ensuring that the wages system is responsive to the needs of a modern competitive industry.

Australia's foreign investment policy has been formulated to encourage foreign investment, consistent with the general objective of ensuring that the Australian community shares fully in the benefits of the development of Australia's industries and resources. The policy recognises the substantial contribution foreign investment has made, and can continue to make, to the development of Australia's industries and resources.

Foreign companies are now not obliged to seek Australian participation in new petroleum exploration and development activities although the Government welcomes, to the extent practicable, a continuing and significant level of Australian involvement in petroleum exploration.

On 1 January 1988, the Government deregulated the market for domestically produced crude oil. Refiners and all crude oil producers can now freely negotiate the quantities and prices of crude oil they buy and sell without Government involvement. In addition, all producers are free to export crude oil as an alternative to selling on the domestic market, except in case of emergencies or subject to export policies such as the prohibition of exports to South Africa.

These changes are aimed at providing an economic framework that is conducive to profitable investment activities in Australia. With this framework, the Government has indicated its objective to provide the right incentive to the petroleum industry to invest and produce, while achieving a fair return to the community for the use of its resources.

Fiscal Regime

Due to the international character of the petroleum industry, investment funds are very mobile and, consequently, petroleum investments are generally made in those countries that offer the most attractive terms. The taxation regime applying to petroleum operations, is, therefore, one of the important determinants of the level of these funds that can be attracted to Australia.

As in most countries, petroleum resources in Australia are vested in the Crown - they are owned by the community. It is the Government's view, also in common with most other oil producing countries, that the community should receive a fair return from the exploitation of the non-renewable resources.

Australia's offshore areas of interest to new explorers are subject to a "Resource Rent Tax (RRT) regime. RRT is essentially a profits based tax which automatically adjusts to changes in project economics, including project costs and fluctuating oil prices. In these areas, no excise or royalty on production is applied. Excise and royalty arrangements continue to apply in the Bass Strait and North West Shelf areas.

Some key features of the RRT include:

- it is a cash flow based tax and tax is only payable in years that a project has a positive net cash flow
- the tax rate is 40% of net cash flow
- all expenditures within the exploration permit area are immediately deductible against receipts for the purposes of calculating net cash flow

- any expenditures that cannot be immediately offset against receipts can be carried forward and compounded at a threshold rate until they can be written off
- the threshold rate is calculated as the long-term bond rate (riskless rate) plus 15% (recognising the risks associated with greenfields exploration).

Under these arrangements, RRT liability is only triggered once the project's rate of return exceeds the threshold rate. This means that no RRT is paid until the project has recovered its exploration, capital and operating costs and earned a rate of return of around 28%. The vital early years of a project are free from any petroleum tax or royalty. In addition, the RRT does not turn a marginal project into a sub-marginal project as may occur with any form of production based tax.

A principal advantage of the profit related RRT is its flexibility. With the provision of immediate deductibility of costs, the RRT automatically adjusts for changes in returns or costs brought about by, say, falling oil prices or the need to move to higher cost enhanced oil recovery. Should net cash flow turn negative at any stage in the project's life, the RRT liability in that year is again zero.

Under the Australian arrangements, RRT is deductible for company tax.

Timor Gap

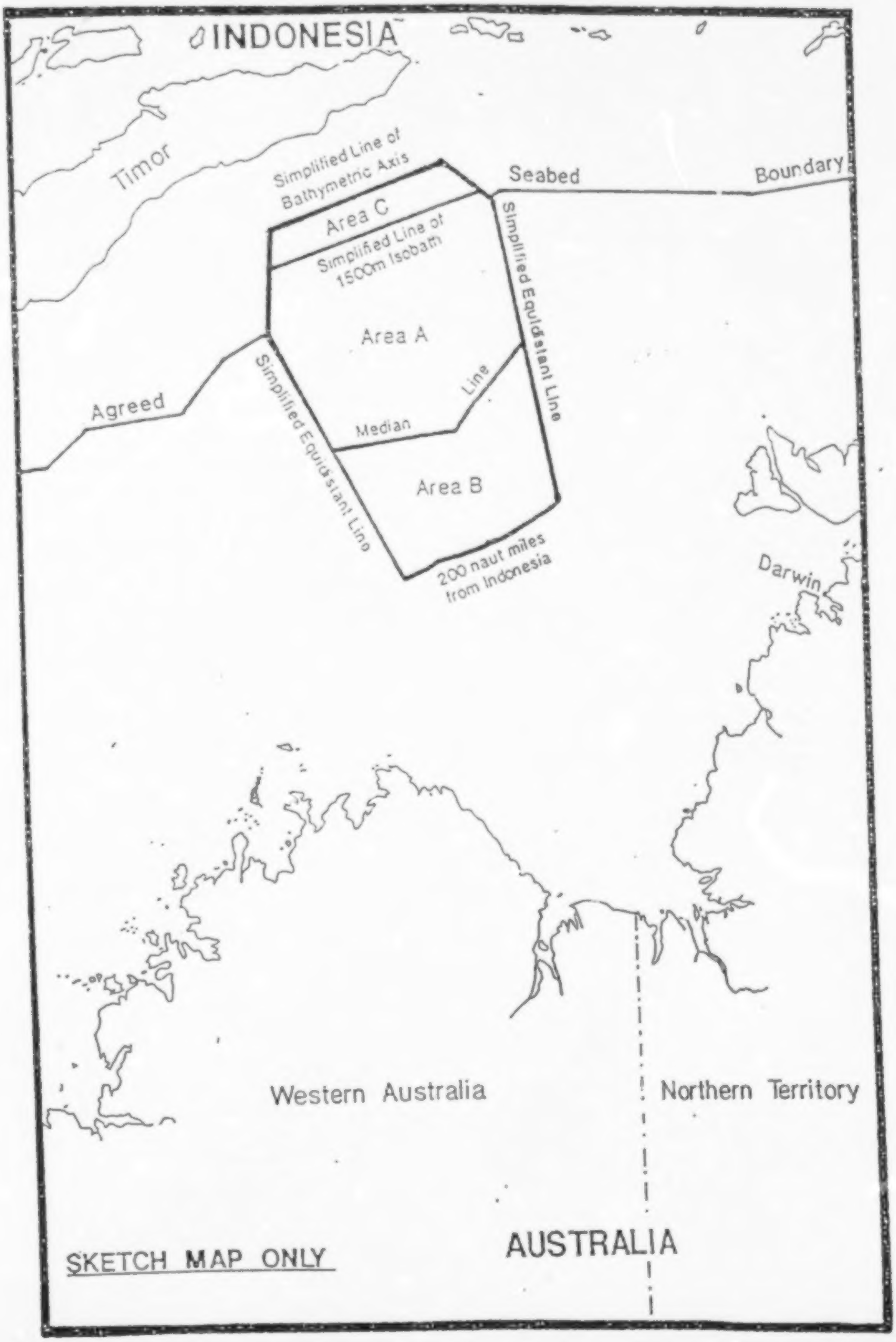
In September 1988, The Australian and Indonesian Governments endorsed the concept of establishing a Zone of Cooperation in the Timor Gap region - an area of disputed sovereignty in the Timor Sea between Indonesia and Australia. Since that time, the two Governments have been working to develop a treaty to implement this concept.

Under these arrangements, the Zone of Cooperation would comprise three areas (see Figure 3). Area A would be developed jointly. Area B would be developed under the Australian regime with Indonesia receiving 10% of Resource Rent Tax collections from the area. Area C would be developed under the Indonesian regime with Australia receiving 10% of the Contractor's Income Tax collections from the area.

It is proposed that the administrative structure will include a Ministerial Council, comprising an equal number of Ministers of each country. The Council would be responsible for broad policy oversight of activities relating to petroleum exploration and production in Area A.

A Joint Authority would be responsible for the day to day operations in Area A. The Authority would be an executive group of an equal number of senior officers nominated by each Government. It would be supported by technical, legal, financial and secretariat groups.

ZONE OF CO-OPERATION


INDONESIA
Timor
Simplified Line of Bathymetric Axis
Seabed
Boundary
Area C
Simplified Line of 1500m Isobath
Simplified Equidistant Line
Area A
Line
Median
Agreed
Simplified Equidistant Line
Area B
200 naut miles from Indonesia
Darwin
Western Australia
Northern Territory
AUSTRALIA
SKETCH MAP ONLY

Despite the complexity of the task, the progress made by Australian and Indonesian officials at their working group meetings is significant and very encouraging. Joint drafts of the Treaty and a mining code for Area A have been substantially completed. A draft model production sharing contract is being prepared. Officials have also agreed the co-ordinates of the Zone and it is hoped that the discussions can be completed in the near future.

Once the Governments have endorsed the Treaty, the necessary actions can be taken to amend appropriate legislation in both countries. The process is expected to be completed by the end of 1990 which will then open the way for exploration to commence in Area A.

Gas Network

All major cities in Australia, with the exception of those in Tasmania, are supplied with natural gas by a pipelines network.

During 1988, 121 terajoules of natural gas were used for electric power generation in Australia, representing some 9 per cent of the energy used for the purpose.

The level of R&D activity in gas has increased. IN 1988-89 $A3.4 million of NERD&D program funds was committed to projects on natural gas for transport. The private sector and State Government bodies - principally gas and transport utilities - have provided a further $A7.8 million over the same period.

Australia's economic reserves of natural gas as at December 1988 have been estimated at 36 trillion cubic feet (tcf). This is sufficient for over 70 years supply at current production levels.

The culmination of over two decades of work on the North West Shelf occurred on 28 July 1989 when the first shipment of LNG left Witnell Bay for Japan. The development of the North West Shelf gas/condensate resource is the largest project undertaken in Australia, with an expected total capital cost of some $A12 billion.

The sale and purchase agreements between the North West Shelf Joint Venture participants (JVP) and the eight Japanese electricity and gas utilities provide for the supply of up to some six million tonnes of LNG a year. This financial year, 2.1 million tonnes is expected to be exported earning around $A500-600 million in 1986 dollars in export income. This should grow to around $A1.5 - 1.8 billion (again in 1986 dollars) by 1994 when exports reach their plateau level.

The North West Shelf will supply Japan with approximately 15 per cent of its LNG requirements for the next 20 years.

The completion of the North West Shelf export phase on budget and ahead of schedule is a good indication of Australian industry's ability to play a major role in technologically highly advanced projects.

CONCLUSION

Australia remains relatively unexplored. Australia has a very large area of territory containing more than 40 sedimentary basins, most of which are lightly explored by world standards. The limited exploration carried out to date has resulted in the discovery of substantial quantities of oil, gas and condensate, and we are confident that the potential remains for further discoveries, both offshore and onshore, in a wide range of geological environments.

In Summary, Australia offers

- access to exciting and challenging offshore exploration acreage
- a stable regime which encourages investment
- freedom to take commercial decisions with minimum direct Government involvement in the process
- a competitive fiscal environment which takes account of changing cost structures and fluctuating oil prices.

This carefully structured approach, and the vast untapped potential of Australia's sedimentary basins, make Australia both an exciting and an attractive place for petroleum exploration.

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Petroleum Information

No.1

LEGAL AND ADMINISTRATIVE ARRANGEMENTS

The legal framework within which petroleum exploration and development activity takes place in Australia is a result of the division of responsibilities between the Commonwealth Government and the State/Northern Territory Governments under the Australian Constitution and certain agreements between the Commonwealth, the States and the Northern Territory. Responsibility for Australia's offshore areas beyond the 3 nautical mile territorial sea rests with the Commonwealth, whereas onshore and within the territorial sea, petroleum operations are the responsibility of the individual State and Territory Governments.

Petroleum operations in Australia, beyond the three mile territorial sea, are governed by Commonwealth legislation known as the Petroleum (Submerged Lands) Act 1967. Within this legal framework the Commonwealth and the States/Northern Territory co-operate in the administration and supervision of industry activities. The legislation provides for orderly exploration and development of petroleum resources and sets out a basic framework of rights, entitlements and responsibilities of governments and industry.

The more important matters covered in the legislation are:

- issue of invitations to apply for exploration permits
- issue of permits to successful applicants, and determination of conditions of the title
- renewal of permits and work programs in the renewal periods
- granting of retention leases over non-commercial discoveries
- granting of production and pipeline licences to successful explorers
- approval of applications for farmouts and transfers of titles
- preparation and issue of regulations, directions, special prospecting authorities,access authorities, authorities for scientific investigations, variations of title conditions, exemption from title commitments and cancellations of titles for non-compliance with the conditions of the title.

Exploration permits are issued under either a work program system or, in selected areas which are considered highly prospective, a cash bidding system.

Except for environmentally sensitive areas (such as the Great Barrier Reef) petroleum operations are permitted on most parts of the continental shelf. Of course, operations must comply with the requirements and standards set by law and factors such as navigation, fisheries and environment are carefully considered, particularly where petroleum production is proposed.

In Australia's onshore areas and within the three mile territorial sea, petroleum operations are governed by the legislation of States and Territories. A two-stage system of exploration permit and production licence has generally been adopted. However, the minimum area, initial term of the permits, and charges and royalties levied vary from State to State.

Additional information on matters coming within the Commonwealth's responsibilities in offshore exploration and development is set out in:

- the Petroleum (Submerged Lands) Act 1967, as amended from time to time, the associated Explanatory Memoranda and Second Reading Speeches;
- a Schedule to the Directions issued under the Act - "Specific Requirements as to Offshore Petroleum Exploration and Production - 1985"; and
- Administrative Guidelines issued to assist with the administration of the legislation.

For further information contact:

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Department of Primary Industries and Energy
Edmund Barton Building
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GPO BOX 858
CANBERRA ACT 2601

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Further information on matters in areas of State/Northern Territory responsibilities can be obtained from the relevant State authority (see attached list).

Department of Primary Industries
and Energy
July 1989

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Petroleum Information

No.2

FOREIGN INVESTMENT POLICY

Australia's foreign investment policy has been formulated to encourage foreign investment, consistent with the general objective of ensuring that the Australian community shares fully in the benefits of the development of Australia's industries and resources. The policy recognises the substantial contribution foreign investment has made, and can continue to make, to the development of Australia's industries and resources.

New Projects

Foreign companies are not obliged to seek Australian participation in their petroleum exploration activities although the Government welcomes, to the extent practicable, a continuing and significant level of Australian involvement in petroleum exploration. Foreign companies granted a new petroleum exploration right by the Commonwealth, State or Northern Territory Governments are not required to seek approval under Australia's foreign investment policy in order to take up that right.

Development proposals, involving foreign companies, with total investment of $10 million or more arising out of petroleum exploration activities are subject to examination under the Government's foreign investment policy. New development projects will be allowed to proceed unless judged contrary to the national interest.

Existing Projects

For the present, proposals to acquire an interest in an existing petroleum exploration right or petroleum production project (through for example, a farm-in transaction) or to acquire an interest in a company holding petroleum exploration or production rights (through for example, the purchase of shares) come within the scope of the Foreign Takeovers Act which requires the company concerned to notify the Treasurer of the proposal. Such proposals are approved unless judged to be contrary to the national interest.

However, the Government has exempted from the Foreign Takeovers Act acquisitions of existing exploration rights and acquisitions of interests in petroleum production projects or companies with total assets of less than $5 million.

Detailed information on the Government's foreign investment policy, including application requirements, is contained in the publication, "Australia's Foreign Investment Policy - A Guide to Investors".

Further information on the Government's foreign investment policy may be obtained from:

The Executive Member
Foreign Investment Review Board
c/- The Treasury
Parkes Place
CANBERRA ACT 2600
AUSTRALIA

Telex: AA62010
Facsimile: (062) 732614
Telephone: (062) 632111

Department of Primary Industries
and Energy
July 1989

AUSTRALIA

Petroleum Information

No.3

MARKETING AND PRICING OF AUSTRALIAN CRUDE OIL

Refiners and crude oil producers are able to negotiate freely the quantities and prices of crude oil they buy and sell both domestically and overseas. Producers are free to export crude oil, as an alternative to selling on the domestic market, except in time of emergency. The freedom to export may also be subject to other relevant policies such as the prohibition of exports to South Africa.

Direct Government involvement in crude oil marketing in Australia, including the determination of the import parity prices for indigenous crude oils ceased on 31 December 1987.

For further information about crude oil marketing arrangements contact:

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Department of Primary Industries
and Energy
July 1989

Petroleum Information

No.4

GENERAL TAXATION ARRANGEMENTS

Company Taxation

Company tax is payable in quarterly instalments in respect of income earned during the previous income year after deducting eligible capital and operating expenses. The company tax rate is 39 per cent of taxable income. For company tax purposes a number of special deductions are available for petroleum exploration and development activities. These deductions, which may be made from income earned from any source, include:

- immediate deduction of petroleum exploration and prospecting expenditure;
- depreciation of capital expenditure on plant at a rate based on the effective life of the asset plus a 20% investment loading - the taxpayer may choose between the straight-line and the declining balance methods of depreciation;
- deduction of capital expenditure on certain petroleum transport facilities in equal instalments over 10 years or, at the taxpayer's option, 20 years;
- immediate deduction of operating costs; and
- an annual option to have excess exploration and development expenditure tax deductions in that year treated as losses under the group loss transfer provisions and transferred to a company with 100 per cent common ownership, be it a parent or subsidiary company.

Capital Gains Tax

A capital gains tax applies to real capital gains (ie. after taking account of inflation) arising from the sale of assets acquired after 19 September 1985. These capital gains are taxed at 39 per cent for companies or, for other taxpayers, at an individual's top marginal tax rate.

For further details see the Income Tax Assessment Amendment (Capital Gains) Act 1986 and associated Explanatory Memorandum and Second Reading Speech.

Imputation System

The imputation system for company dividends removes the long-standing problem of income distributed to resident shareholders being taxed at the company level and again when distributed as dividends. Under the system, an Australian resident company is required to maintain a special dividend franking account (DFA) which is credited with franked dividends the company receives from other companies plus an amount equal to the after-tax income of the company (the after-tax income is equal to the gross income less eligible deductions less tax paid). Dividends will be required to be paid first from the DFA and such dividends will be known as 'franked dividends'.

A resident shareholder receiving a franked dividend from a company is entitled to an imputation credit equal to 49 cents for every 51 cents of franked dividend received (the rate of credit will be reviewed when consideration is given by the Government to reductions in personal income tax rates). The shareholder is assessed for tax on the amount of the dividend plus the imputation credit, and then the credit is offset against the tax assessed. For shareholders on the maximum marginal tax rate (that is currently 49 per cent), the imputation credit will effectively free the dividends from tax in the shareholder's hands, while shareholders on lower marginal rates may use excess credits to offset any tax assessed on other income. Where the shareholder is unable to utilise the excess credits, however, cash refunds will not be allowed.

Unfranked dividends will be treated as assessable income of shareholders and will not carry an entitlement to imputation credits.

Franked dividends paid to non-residents are exempt from Dividend Withholding Tax (DWT), while unfranked dividends remain subject to DWT which is imposed at a rate of 30 per cent, but reduced to 15 per cent for residents of countries with which Australia has a double tax treaty.

For further details see the press statement by the Treasurer, "Business Tax Reform: Ending the Double Tax on Company Dividends", released on 10 December 1986.

Double Taxation Agreements and Foreign Tax Credits System

Australia has concluded comprehensive agreements with a number of countries for the elimination of double taxation. In general, the agreements provide for the primary taxing right to lie with the country of source of income, and for the country of residence to allow a tax credit.

Under the Foreign Tax Credits System, the foreign source income of Australian resident taxpayers (apart from salary and wages) and corporate dividends where the Australian company holds less than 10% voting interests in the foreign public company, will be subject to Australian tax, with a credit being allowed against Australian tax for foreign tax paid on that income. Except for certain interest income, foreign source income will be aggregated and assessed on a worldwide basis.

From 1 July 1989, the Foreign Tax Credit System will exempt from Australian company tax income earned by subsidiaries or branches of resident companies operating in non-tax haven countries (ie countries with a broadly similar tax system to Australia which includes all of our major trading partners).

For further details see the Taxation Laws Amendment (Foreign Tax Credits) Bill 1986 and associated Explanatory Memorandum and Second Reading Speech.

Inquiries on general taxation matters should be directed to:

The Commissioner of Taxation
2 Constitution Ave
CANBERRA CITY ACT 2600
AUSTRALIA

Telex: 62187
Facsimile: (062) 472830
Telephone: (062) 752222

Department of Primary Industries
and Energy
July 1989

Petroleum Information

No.5

PETROLEUM TAXATION ARRANGEMENTS - RESOURCE RENT TAXATION

In addition to general taxation arrangements applying to companies in Australia, petroleum production projects in Australia are also subject to secondary taxes, consisting of resource rent tax, or excise and royalties. The type and rate of secondary taxation depends on the location of the petroleum resource, the date of discovery of the petroleum reservoir and the date upon which production commenced.

The taxation regimes aim to provide a fair and reasonable return to the Australian community for the exploitation of these non-renewable resources, while at the same time providing an incentive to companies to explore for and develop the resources.

The resource rent tax (RRT) applies to petroleum projects in the majority of Australia's offshore areas beyond the territorial sea. The areas excluded are the Bass Strait and North West Shelf production licence areas and associated exploration permits. Where RRT applies, it replaces excise and royalties which would otherwise have been levied.

The key features of the RRT are:

- the RRT applies to net cash flows after returns on project-related expenditures exceed the specified threshold limit - equivalent to the Australian long-term bond rate plus 15 percentage points. Any excess of project-related expenditures over receipts in a financial year may be compounded forward at the threshold rate;

- RRT is levied at a rate of 40 per cent and any RRT payments are deductible for company tax purposes. Provisional instalments of RRT are payable quarterly in the year of tax liability;

- the tax is assessed on a project basis, where a project is considered as an integrated investment including facilities and operations necessary to produce a "marketable" product
  - only expenditure and income directly related to the project, including social infrastructure, are within the scope of the RRT;

- RRT applies in respect of income from the recovery of all petroleum, including crude oil, condensate, natural gas, LPG and ethane;

- exploration expenditure within the original exploration permit area from which the associated production licence(s) is drawn is an eligible deduction for RRT purposes
  - only eligible exploration expenditure incurred after 1 July 1979 is eligible for RRT purposes

  - eligible undeducted exploration expenditure incurred in the 5 year period before the granting of a production licence is compounded forward at the threshold rate; expenditure prior to that 5 year period is compounded forward at a rate equal to the GDP deflator;

- RRT liability for a project is not influenced by changes in ownership or farm-in agreements. Joint Venturers will be assessed on an individual participant basis;

- cash bids for offshore exploration areas are not eligible deductions for RRT purposes but are deductible against income tax or capital gains tax;

- royalty income from override royalties is not liable to RRT, consequently such royalties are not eligible deductions for RRT purposes; and

- deductions are allowable for all project closing-down costs, including environmental restoration of a project site.

Further details of the RRT are outlined in:

- a press statement "Resource Rent Tax on 'Greenfields' Offshore Petroleum Projects" released by the Treasurer and the Minister for Resources and Energy on 27 June 1984;

- a press statement "Resource Rent Tax on 'Greenfields' offshore Petroleum Projects: NT/P26 and End-of-Project-Life Adjustments" released by the Treasurer and the Minister for Resources and Energy on 20 May 1985; and

- the Petroleum Resource Rent Tax Assessment Act 1987 and associated Explanatory Memorandum and Second Reading Speech.

A simple example of the operation of the RRT is attached.

Further information on the RRT applying in Australia's offshore areas and details of the excise and royalty arrangements applying elsewhere can be obtained from:

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Petroleum Division
Department of Primary Industries and Energy
Edmund Barton Building
CANBERRA ACT 2600
AUSTRALIA

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Facsimile: (062) 724137
Telephone: (062) 723933

Department of Primary Industries
and Energy
July 1989

ATTACHMENT

SAMPLE CALCULATION OF A PROJECT'S RRT LIABILITY

The following simple example illustrates the operation of the petroleum resource rent tax in the initial years of a petroleum project. It assumes the following:

- a single company holds an exploration permit, acquired on 1 July 1986, in an area to which RRT will apply;
- in the financial year to 30 June 1987, the company incurs exploration expenditure of $50m within the permit area;
- in the financial year 1987/88, the company expends a further $20m on exploration and discovers a substantial pool of petroleum. A further $1m expenditure is incurred that year in relation to the company's application for a production licence to develop the discovery;
- in 1988/89 the production licence comes into force and the company expends $100m in start up and production costs; and
- in both 1989/90 and 1990/91, the company's production expenditure is $20m and petroleum to the value of $200m is recovered and sold.

The RRT would apply as follows:

	$MILLION				
	86/87	87/88	88/89	89/90	90/91
Receipts	-	-	-	200	200
Less Expenditure					
Exploration	50	20	-	-	-
Development and Other	-	1	100	20	20
Net Annual Receipts[A]	-50	-21	-100	180	180
Undeducted Expenditure[B]	-	-65	-111.8	-275.3	-123.9
Accum Net Receipts	-50	-86	-211.8	- 95.3	56.1
Tax @ 40%	-	-	-	-	22.4

A. Annual receipts less annual expenditure.
B. Undeducted expenditure is carried forward at the threshold rate assumed to be 30 per cent in this example.

Figures have been rounded.

Department of Primary Industries
and Energy
July 1989

Petroleum Information

No.6

OFFSHORE PETROLEUM TITLES

Petroleum industry activities in Australia, beyond the three nautical mile territorial sea, are governed by Commonwealth legislation - the Petroleum (Submerged Lands) Act 1967. The legislation makes provision for three types of title to be granted to companies: exploration permits, retention leases and production licences.

An exploration permit provides exclusive rights to undertake seismic surveys and drilling in a defined area. A production licence is granted for the recovery of petroleum following a commercial discovery. Where a discovery is not commercial but is expected to become so, a retention lease may be granted.

In areas not covered by titles, companies may be granted a special prospecting authority to undertake seismic or other geophysical or geochemical survey work. This is a non-exclusive right to explore an area prior to the invitation for applications for an exploration permit. A special prospecting authority over an area does not provide any rights in relation to the award of an exploration permit.

Exploration Permits

Exploration permits are awarded by one of two possible means: a work program bidding system, or a cash bidding system. Prospective acreage is released twice a year, and companies are encouraged to advise the Commonwealth of areas of interest.

The work program bidding system is the traditional method of awarding offshore exploration permits in Australia and is used in the vast majority of cases. Under this system, an applicant is required to propose an exploration program over six years. The first three years of the program is known as the "minimum guaranteed dry hole work program", and only includes work of an exploratory (rather than appraisal) nature. All the work must be completed to avoid cancellation of the permit. The applicant also identifies a "secondary" work program to cover the second three years of the permit.

Work program permits are issued for an initial six years, and may be renewed for an unlimited number of five year periods. At each renewal 50% of the permit area must be relinquished. Work program permits generally cover an area of around 11 000 square kilometers.

The cash bidding system was introduced in 1985, and is only used in areas of high prospectivity. An exploration permit is awarded to the highest cash bidder. As there is no obligation to undertake any program of exploration, the successful applicant can choose the appropriate time and market conditions to act on the investment in the permit.

Cash bid permits are issued either for six years, or for an initial six years with an option of a five year renewal at the end of that period. As with work program permits, 50% of the area must be surrendered upon renewal. A cash bid permit can only be renewed once (and then only if this renewal option was determined at the outset), but no further cash bid is necessary upon renewal. Cash bid permits are generally around 2 500 square kilometres in area.

Retention Leases and Production Licences

Upon discovering petroleum, a permittee must notify the authorities, giving details of the discovery. Before taking out a retention lease or production licence, the permittee must identify the block or blocks which cover the area of a discovery. This is known as 'declaring a location'.

Upon declaration of a location, the permittee may undertake further exploration in the location to determine more accurately the nature of the discovery. The permittee may also apply to vary the size of the location, or even to have the location revoked, if the discovery is thought to be ultimately non-commercial.

If the discovery is commercial, the permittee may wish to apply for a production licence. Usually, the permittee has two years after the declaration of location in which to apply for a production licence, and provide details of work and expenditure proposals for the area. Production licences are issued for twenty one years, and may be renewed for further periods of twenty one years. Where production facilities require a pipeline to transport petroleum to shore, a pipeline licence will be granted for the same periods of time.

If a permittee makes a non-commercial discovery that is expected to become commercial within the next fifteen years, an application may be made for a retention lease rather than a production licence. As with a production licence, the permittee usually has two years after declaration of the location in which to apply for a retention lease, and provide an assessment of the commercial prospects of the discovery.

Retention leases are issued for five years, with renewal periods of five years. At each renewal of a retention lease, the lessee must demonstrate that the discovery is likely to become commercial within the next fifteen years.

Where a location is not revoked, if the permittee does not apply for a production licence or a retention lease within the specified time, the exploration permit in respect of the blocks covered by the location will be terminated.

Titleholders' Obligations

The legislation provides that all titleholders must carry out operations according to good oilfield practice, and in a manner which maximises recovery of petroleum, is safe and prevents the escape of petroleum into the environment. In order to retain title, conditions of work must be met and annual rental fees paid.

Additional information on matters relating to the Commonwealth's offshore petroleum legislation is contained in:

- the Petroleum (Submerged Lands) Act 1967, as amended from time to time, the associated Explanatory Memoranda and Second Reading Speeches;
- a Schedule to the Directions issued under the Act - "Specific Requirements as to Offshore Petroleum Exploration and Production - 1985"; and
- Administrative Guidelines issued to assist with the administration of the legislation.

For further information contact:

First Assistant Secretary
Petroleum Division
Department of Primary Industries and Energy
Edmund Barton Building
CANBERRA ACT 2600
AUSTRALIA

GPO Box 858
CANBERRA ACT 2601

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Department of Primary Industries
and Energy
July 1989

AUSTRALIA

Petroleum Information

No.7

PROPOSED AUSTRALIAN/INDONESIAN ZONE OF COOPERATION IN THE TIMOR GAP

On 25 October 1988, the Minister for Foreign Affairs and Trade, Senator Evans and his Indonesian counterpart, Mr Alatas, announced that the two Governments had endorsed the officials recommendation to establish a Zone of Cooperation in the Timor Gap region and that appropriate steps be taken to complete a comprehensive agreement on the Zone.

The proposed Zone of Cooperation is intended to allow exploration for and exploitation of petroleum resources in the Timor Gap region. It has no implications for other resources or activities in the region.

The proposed Zone of Cooperation is an interim measure pending agreement between Australia and Indonesia on the delimitation of a permanent seabed boundary in the area known as the Timor Gap (being the gap opposite East Timor in the seabed boundaries agreed between the two countries in 1971 and 1972 - see attached map).

The proposed Zone of Cooperation comprises three areas (see map):

- Area A where joint Indonesian and Australian administration will manage petroleum exploration and production activity and where revenue collected by the joint administration will be shared 50/50 between Australia and Indonesia;
- Area B in which petroleum industry activities will take place under relevant Australian laws, but from which Australia agrees to share with Indonesia 10% of gross Resource Rent Tax (RRT) revenues (this is equivalent to 16% of net RRT after taking account of the deductibility of RRT against company tax); and
- Area C in which petroleum industry activities will take place under relevant Indonesian laws, but from which Indonesia agrees to share with Australia 10% of any company tax revenues (the Indonesian company tax system is project based in a similar way to RRT).

The initial term proposed for the Zone of Cooperation is 40 years. It is proposed that the Zone of Cooperation may be extended for further 20 year terms after the initial 40 year term. However, the Zone of Cooperation may be terminated at any time in the event that the two Governments agree to a permanent seabed boundary.

Before a formal Agreement to establish the Zone of Cooperation can be signed by the two countries, detailed mining, taxation and legal regimes to apply in Area A need to be developed. Working groups comprising Australian and Indonesian officials have been established for this purpose with a view to reporting back to Governments as soon as possible. Some of the guiding principles for the working groups include:

- development of a joint Australian/Indonesian administration, consisting of a Ministerial Council and a Joint Authority, which will have the responsibility of implementing the mining, taxation and legal regimes;
- development of a mining regime which will ensure the efficient, safe and environmentally sound exploration, development and production of petroleum resources by companies;
- development of a profit sensitive production sharing contract which will provide an attractive environment for investment in petroleum exploration and production, and at the same time ensure that an appropriate level of revenue is collected;
- adoption of existing Australian and/or Indonesian laws covering such things as migration, customs, quarantine, employment, health and safety, contractural relationships, and civil and criminal matters;
- arrangements for security and surveillance of any petroleum structures; and
- development of dispute settlement procedures to be followed by the two Governments, with emphasis on consultation and negotiation between the two Governments as the primary means of resolving disputes.

The Australian Government intends to keep the petroleum industry fully informed of the direction and progress being made by the working groups.

Any enquiries concerning the Zone of Cooperation should be directed to: First Assistant Secretary
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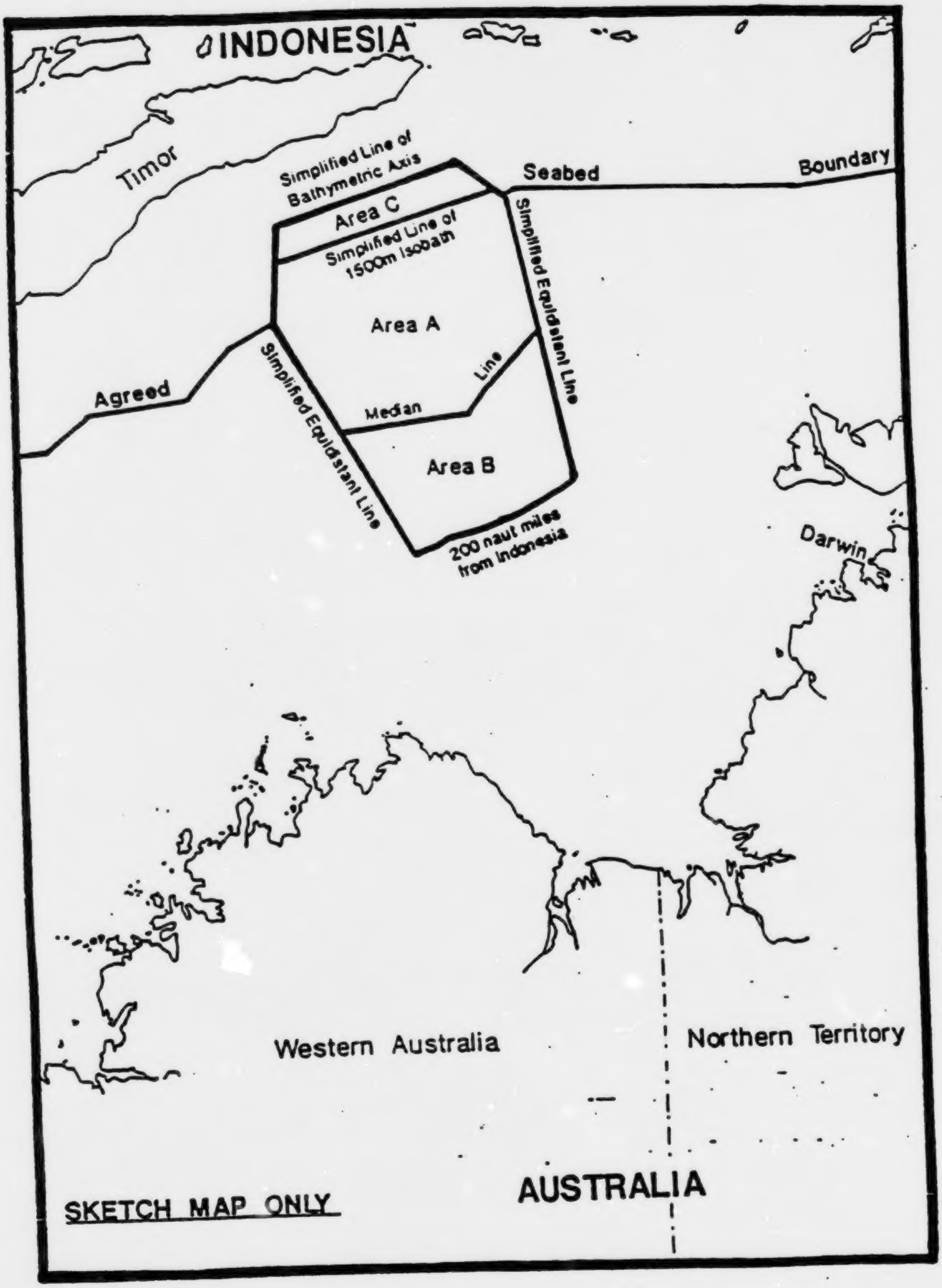
Department of Primary Industries
and Energy
July 1989

ZONE OF CO-OPERATION


INDONESIA
Timor
Simplified Line of Bathymetric Axis
Seabed
Boundary
Area C
Simplified Line of 1500m Isobath
Area A
Simplified Equidistant Line
Agreed
Simplified Equidistant Line
Median
Line
Area B
200 naut miles from Indonesia
Darwin
Western Australia
Northern Territory
AUSTRALIA
SKETCH MAP ONLY

"THE STRATEGY OF THE U.S. PRODUCER"

Presented by

J. D. McColgin
President and General Manager
Conoco Canada Limited
Calgary, Alberta

at

CANADIAN ENERGY RESEARCH INSTITUTE

INTERNATIONAL OIL AND GAS MARKETS CONFERENCE

CALGARY, ALBERTA

October 22 - 24, 1989

Session: Exploration and Development in the 90's

"THE STRATEGY OF THE U.S. PRODUCER"

Good afternoon, Ladies and Gentlemen

In continuing with our theme of oil and gas exploration and development in the 1990's, I would like to spend the next few minutes discussing the strategy of the large U.S. multinational producer.

Strategy implies a plan of action designed to achieve a set of goals. When mentioning goals, I think in terms of two categories: stated and unstated. The stated goals are the ones that are generally published or openly talked about by companies. These include the most commonly cited ones of financial performance. Secondly, there are environmental goals covering how a company will handle their operations in order to protect the environment. Obviously these have become very important in the last few years. Thirdly, there are ethical goals. These state how a company intends to deal with its partners, how it treats its employees, and its perception of its responsibility to the local community in which it operates.

In addition, there are 'unstated goals' which are extremely important when trying to understand the actions taken by a company. The most common 'unstated goal' is that of preservation or self-continuation of the organization itself.

I would like to focus this afternoon on the 'stated' financial goals and the 'unstated goal' of self-continuation, as I think these have an important bearing on how a company devises its strategy for the future.

Turning to financial measurements, there are a number of these typically used. Common ones include return on equity, and the valuation of projects by looking at their net present value and a projection of their cash flows. Each of these financial measures has inherent within it an expectation of crude oil price. The next slide shows the actual oil price for crude oil in U.S. dollars from 1960 through 1989 in terms of 1988 dollars. The price of oil declined slowly from 1960 to 1973. This was followed by rapid increases from 1973 through 1981, and a subsequent sharp decline through 1986. Looking forward, in the published brochure "World Energy Outlook through 2000", Having briefly mentioned sets of goals, I would now like to focus on the strategies being used by U. S. producers to meet them. A major change during the latter part of the 1980's is a re-emphasis on vertical integration. As oil prices fell in 1986, upstream earnings from exploration and production fell dramatically; but downstream earnings from refining and marketing were at record highs throughout the United States. Companies again saw the benefit of being vertically integrated. In the early 1980's, most capital budgets within large U.S. oil companies were focused on exploration and production. In the future we will see an increased interest in expanding marketing outlets, refineries, and other downstream operations.

A second major strategy is divestment of non-oil and gas businesses. There is a clear recognition that the management expertise that allows a company to succeed in the oil and gas business may not carry over into merchandising, office equipment, mining, or other non-related fields. We are seeing a spinoff of these other activities. Management of oil and gas companies is now focusing on the core business that it understands and knows best. Additionally, there is a realization today that the stock market itself does not put a value on diversification. The individual investor prefers to buy shares in a number of companies in order to diversify his risk. Diversification within a company may actually decrease its share value.

A third strategy is that of geographical diversification. Many companies are presently increasing the number of countries in which they operate. Companies are focusing on areas that have not been extensively explored and thus have large remaining reserve potention. If oil prices fall sharply, companies do not want to be faced with financial disaster. On the other hand, if prices go up dramatically, they want their earnings to increase significantly. The next slide, although somewhat conceptual and simplified, clearly demonstrates the earnings benefits derived from geographical diversification by looking at three different situations. Looking at the curve showing earnings versus oil price for North American exploration and production one sees an earnings curve that has a steep slope. Finding and operating costs in North America are typically much higher than elsewhere in the world. Thus it is not justified to do a lot of exploration for oil at prices below $16 or $17/barrel. The high finding cost in this mature fuel compared to fuel oil and coal and the demand for it is expected to increase.

As a result of the previous two assumptions, it is anticipated that gas will soon approach price parity with oil on an energy equivalent basis. It may even sell for a premium in selected markets.

Finally, it is assumed that there will be a large increase in Canadian gas exports to the United States.

The fifth strategy of U.S. producers is to consolidate their operations. In the past large companies tended to try to be in every play. Today we see a focusing of effort. Companies are beginning to sell or trade remote fields while increasing their interest in areas where they have a number of fields to operate. We see swaps of interests in fields between operators to consolidate holdings. Additionally, on the exploration front, companies are looking at fewer plays than in the past. This decreases the cost that a company has in maintaining its databases and reduces the number of exploration staff needed. Finally, we see a centralization of offices in an effort to again reduce the number of employees and to reduce overhead.

A sixth strategy of many companies is to maintain or increase their reserve base. Looking at a slide of a typical company showing reserves over the past fifty years, one would see that reserves, particularly in North America, have generally been decreasing since the 1960's. Companies are attempting to maintain their reserve base firstly through high-graded exploration and secondly, through enhanced recovery techniques and improved production practices. For example, one sees major investments being made in CO_2 floods in old oilfields within the United States. Thirdly, companies seek to maintain their reserve bases through acquisitions. In many cases, companies have found it less expensive to buy an entire company than to try to buy individual assets. As a result, we have seen a large number of corporate acquisitions consummated.

Another strategy is to focus on large fields. Selected companies have sold off a group of small fields and then re-invested the funds on a single large

"OIL AND GAS EXPLORATION AND DEVELOPMENT IN THE 1990'S, THE CANADIAN SCENE"

Presented by

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EIGHTH CERI INTERNATIONAL
OIL AND GAS MARKETS CONFERENCE
Calgary, Alberta
October 22-24, 1989

Like in any other theater of upstream operations the future level of activities in Canada will be governed by the **perceptions** oil companies have with regard to:

- Remaining Resource Base
- Pricing of Oil, Gas, Bitumen, Sulphur
- Regulatory and Fiscal Systems
- Political Factors and Environmental Concerns potentially impacting the Business
- Application of (new) Technology and related Cost
- Economics related to all the above

Let me touch in the following on some of these elements and thereby try to develop a view on how the Canadian Exploration and Development scene might develop over the next decade.

Oil companies readily concede that they have a dismal record in forecasting **Oil Prices**. Despite this shortcoming, forecasts are always required as input to formulation of business strategies for the future. Under the impression of the 1986 price plunge and the currently still largely unchanged imbalance of international supply and demand most of the industry planners will probably think it prudent to assume that international oil prices will remain in the US $15-20/B (Persian Gulf) price bracket well into the 1990's. Oil being an internationally traded commodity, Canadian prices are expected to closely track international levels. This means prices in the range of C$ 20 to 30 f.o.b. Edmonton for light oil and C$ 10 to 15 for **Bitumen**. This has a few implications.

There is more optimism with regard to **Gas Prices**. They are expected to firm up over the medium term future. There are two driving forces for this: (1) North America is expected to develop more and more into an integrated market. Indications are that US indigenous supplies are getting tight which means that there should be a growing opportunity for

Canadian gas in this market. (2) Gas is a relatively clean burning fuel. With the growing concern about our environment demand for gas should rise and this be reflected in firming prices.

Sulphur Pricing has been erratic in the past and is likely to behave in a similar fashion also in future. Sulphur in the Canadian scene being largely a by-product of gas production, its price will probably have little effect on the overall level of future upstream activities.

If we consider the **Resource Base** we note that practically the entire Canadian production of oil and gas has been, and still is from the Western Canadian Basin, located between the Rocky Mountains and the Canadian Shield. The basin has been covered by several million kilometres of seismic and been tested by some 150 000 wells. This means that the exploration maturity of this basin is relatively high, especially in comparison to most other hydrocarbon provinces outside of North America. This fact is not lost on Canadian oil companies, many of whom sense greener pastures abroad and have been trying for some time to build up their overseas portfolio of upstream investments.

Oil Exploration in the Western Basin has become a questionable proposition indeed. Analyzing industry data one finds that the larger and medium sized oil fields had largely been found by the end of the 1960's. For the past 20 years it took an average of 300 oil exploration wells for every new pool discovery larger than 3 million barrels.

Over the period of the last 10 years industry average oil finding and development costs were around C$ 11-14/B, including acreage acquisition and overhead costs. With average operating cost of C$ 5-6/B, royalties of some 25%, and taking into account the cost of money, it is clear that, at least for the average oil finder, there remains little profit to be made at oil prices projected for the early to mid 1990's.

Some of the smaller oil companies, even some of the larger ones, have done well in finding oil well below the industry average finding cost. Even so, at least for the larger companies, the fact remains that the odds of making a discovery that could have a real impact on the bottom line, say a find larger than 20 million barrels, have become too long to play. Therefore I conclude that most of the larger oil companies will be disengaging from oil exploration in the Western Basin and leave the field to junior producers, that have low overhead costs and pay little or no royalties. With diminishing competition, acquisition prices for new acreage should drop which in turn will help the junior producers to remain in business for quite a while to come.

The question arises whether **New Exploration Technology** - to which larger companies typically have access - could help these players to remain in the oil game. Seismic for example has made great strides in the past 10 years with 3D acquisition, ever more sophisticated processing and computer assisted interpretation technologies.

It is interesting to note that 3D seismic is hardly used in the Western Basin for exploration purposes. The underlying reason, at least in my experience, is the land tenure system. 3D is expensive and you really can only afford to bring it to bear if you hold the acreage. When tackling an exploration play in the Western Basin this is typically not the case. Every exploration manager is familiar with the dilemma of whether to shoot detailed seismic first and then try to assemble an acreage position or the other way round.

Enhanced Recovery Projects - some of them economic at current oil prices - will stem somewhat the decline in oil production from the Western Basin but will not have sufficient impact to reverse the trend.

Prospects for **Gas in the Western Basin** are rated considerably more favourable than for oil. Quality gas reserves are generally found in the downdip, deeper parts of the autochthonous basin fill and in the Foothills. These areas are less densely explored and the chances of making large size new discoveries are very real.

The combination of good exploration potential and optimistic market outlook for gas has prompted quite a number of the larger and smaller companies recently to redirect their upstream strategies. This has already been reflected in an increasing number of gas wells being drilled, escalating acreage prices and the appearance of new players in some remote geographical areas where only few dared to tread in the past. Some of these gas plays in remote and rugged areas take a long time to mature to the development stage. To be successful will require application of sophisticated technology and a long term commitment coupled with considerable financial muscle. I see it mainly as a game for the larger companies.

What will the industry activity be in the **Canadian Frontier Basins** ? There is no denying that in the current (post - NEP) period activities are at an all time low. This simply reflects economic reality. Even large oil fields already found and appraised like Hibernia and Amauligak cannot be developed economically under oil pricing assumptions I have indicated earlier. To do so in the hope of higher oil prices may be risking the financial future of the companies involved. It follows that these development projects will only go ahead in the early 90's if government assumes a large part of the downside risk.

It is a political question whether government should accept - on behalf of the taxpayer - risks in hydrocarbon exploration and development that are higher than those found acceptable by the private sector. I am of the opinion that industry should not expect government to subsidize on a broad scale activities that do not meet commerical profitability criteria - including an assured, reasonable economic rent for the state.

A prime example of ill conceived subsidies was the federal PIP program of the 1980's. A lot of expensive wells were drilled that did not make much sense even then, under the expectation of much higher oil prices. Resources were wasted at taxpayers' expense.

A majority of oil companies will find it difficult to convince themselves to further explore in the Frontier Basins until such time when some of the large oil and gas fields already found can be developed profitably. For this reason, I believe, we will see upstream activities in the Canadian Frontier to be largely development driven in the early and mid 1990's.

The Hibernia development project, with a safety net provided by government, will probably go ahead in the next few years. I hope we will see development of the Terra Nova field with innovative technology and on a sound economic footing by the mid 90's. Amauligak may have to wait for higher oil prices, later in the decade.

If gas prices firm up and the issues around native rights in the Northwest Territories can be resolved in good time, we should see a Mackenzie Delta gas development take shape in the mid 90's concurrent with or followed by gas development in the Nova Scotia offshore.

Apart from having great difficulties to pass company internal economic screening at the present time, Frontier exploration is also being held in check by some unresolved political issues and a growing concern about the environment. Some areas have been placed under moratorium for environmental reasons. In other areas the question of who is the landlord is undecided. Still a few companies, taking a very long term view, remain in general terms interested in Canadian Frontier exploration. Governments too, at least in principle, seem eager to see such activities, especially offshore the East Coast, in the Northwest Territories and the Beaufort Sea. Governments could promote industry interest by addressing certain specific issues:

1) Settle the native rights issues in the Northwest Territories and the Yukon. It is a precondition to making exploration rights available.

2) Conclude the Pacific and Northern Accords. Industry would like to know the fiscal and regulatory terms that are intended to govern their operations.

3) Government can help to develop the long term view required for Frontier exploration by tailoring the acreage tenure terms accordingly. Currently stipulated 3 plus 3 and 5 plus 4 years exploration periods are both too short. 12-15 years are required in today's business environment.

4) The current stipulation of 50% Canadian ownership in future Frontier development projects may be politically expedient but acts as a deterrent to exploration. Since the demise of the PIP regime and restructuring of the industry only very few Canadian owned companies exist that are able to share the heavy front end risks in Frontier exploration. Conversely, to take all the exploration risks and later be forced to divest in the rare success case is not attractive to a company or joint venture that is in its majority foreign owned.

I have so far not touched on **Oil Sands, Bitumen and Heavy Oil**. Obviously the resource base is huge. Current prices make existing operations, some 600 000 B/D in total, marginally cash positive but unattractive as far as further field development and construction of upgrading is concerned. The economic situation is somewhat similar to that of Hibernia. Only government risk guarantees or outright subsidies could bring about development projects like OSLO and Lloydminister at the present time. Otherwise projects will have to wait until oil prices are firmly in the US$ 20 to 25/B bracket. However, some of the oil sand development projects on the drawing boards of various companies could reach the commerciality threshold at lower oil prices than required for Hibernia.

Taking the long term view, the oil sand deposits are clearly Canada's most important non-renewable resource. Self sufficiency in oil is virtually guaranteed for as long as required.

A growing public debate is centred around **Energy and the Environment** with focus on the reduction of CO2 emissions, seen related to the threat of a greenhouse effect. A target of a reduction by 50% of CO2 emissions from currently forecast levels for the year 2005 is being mentioned. It is difficult to envisage reaching such a target without drastically changing the lifestyle of Canadians.

It is still early in the debate but it is clear that the energy industry will be challenged in more than one way during the 90's. I have mentioned the growing attractiveness of natural gas in this context. It is also obvious that the nuclear option needs to be revisited. An early fall-out of the debate no doubt will be protracted scrutiny of every new project initiative dealing with energy and fossil fuels.

As you can see, ladies and gentlemen, I view the Canadian upstream scene for the next decade as rather a mixed bag. Some threats, some excellent opportunities, some marginal propositions. However, as we see time and time again, somebody's junk can become somebody else's treasure. That is afterall what makes our industry so exciting.